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# IEEE Std 3004.11-2019

Recommended Practice for Bus and Switchgear Protection in Industrial and Commercial Power Systems

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# IEEE Recommended Practice for Bus and Switchgear Protection in Industrial and Commercial Power Systems

Developed by the

**Industrial and Commercial Power Systems Standards Development Committee**
of the
**IEEE Industry Applications Society**

Approved 5 September 2019

**IEEE SA Standards Board**

**Abstract:** Covered in this recommended practice is the protection of bus and switchgear used in industrial and commercial power systems. Also provided are fault protection and isolation strategies for the substation bus and switchgear, including the bus, circuit breakers, fuses, disconnecting devices, transformers, and the structures on which they are mounted.

**Keywords:** arc flash, arc flash protection, differential protection, double-ended substation, high impedance bus differential relay, IEEE 3004.11™, percentage differential relay, tie circuit breaker

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## Introduction

This introduction is not part of IEEE Std 3004.11-2019, IEEE Recommended Practice for Bus and Switchgear Protection in Industrial and Commercial Power Systems.

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When this project is completed, the technical material included in the 13 "color books" will be included in a series of new standards. Approximately 60 "dot" standards, organized into the following categories, will provide in-depth treatment of many of the topics formerly covered in the color books:

— Power Systems Design (3001 series)
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— Power Systems Grounding and Bonding (3003 series)
— Protection and Coordination (3004 series)
— Emergency, Stand-By Power, and Energy Management Systems (3005 series)
— Power Systems Reliability (3006 series)
— Power Systems Maintenance, Operations, and Safety (3007 series)

In many cases, the material in a "dot" standard comes from a particular chapter of a particular color book. In other cases, material from several color books has been combined into a new "dot" standard. The material in this recommended practice replaces Chapter 13 of IEEE Std 242-2001, (*IEEE Buff Book*™).

## IEEE Std 3004.11™

This publication provides a recommended practice for the electrical design of commercial and industrial facilities. It is likely to be of greatest value to the power-oriented engineer with limited commercial or industrial plant experience. It can also be an aid to all engineers responsible for the electrical design of commercial and industrial facilities. However, it is not intended as a replacement for the many excellent engineering texts and handbooks commonly in use, nor is it detailed enough to be a design manual. It should be considered a guide and general reference on electrical design for commercial and industrial facilities.

Tables, charts, and other information that have been extracted from codes, standards, and other technical literature are included in this publication. Their inclusion is for illustrative purposes; where technical accuracy is important, the latest version of the referenced document should be consulted to assure use of complete, up-to-date, and accurate information.

## Contents

# IEEE Recommended Practice for Bus and Switchgear Protection in Industrial and Commercial Power Systems

## 1. Scope

This recommended practice covers the protection of bus and switchgear used in industrial and commercial power systems. It provides fault protection and isolation strategies for the substation bus and switchgear, including the bus, circuit breakers, fuses, disconnecting devices, transformers, and the structures on which they are mounted.

### 1.1 General discussion

Switchboards and switchgear are the parts of the power system used to direct the flow of power to various feeders or branches and to isolate apparatus and individual circuits from the power system sources. These parts include the bus bars, circuit breakers, fuses, disconnection devices, current transformers (CTs), voltage transformers (VTs), instrumentation, and the structure on or in which these are mounted. The term bus usually refers to the principal conductive components within an assembly of equipment such as medium-voltage (MV) metal-enclosed switchgear, MV control, low-voltage (LV) switchgear, power switchboards, panelboards, motor control centers (MCCs) and bus duct, a.k.a. busway (see IEEE Std 3001.5™ for information concerning the application of this equipment). Electrically a bus may be defined as any conductor with one or more sources and two or more connected loads with independent switching and protective devices. From the perspective of arc-flash hazard analysis, the line-side bus of a main device is often considered as part of the main equipment bus. To reduce the arc-flash incident energy, protection of line-side conductors must also be considered, even if they are protected by a device on the primary of a transformer.

Several factors have contributed to increasing interest in the improving protection of buses in industrial and commercial power distribution systems. These include:

- Increased short-circuit levels;
- Increased use of in-plant generators and distributed generation increasing the requirement for fast fault clearing, which is needed to maintain generator stability and to allow coordination between generator protection and load-side feeder protection;
- Increased need for reliability;
- Increased use of bus transfer schemes;

— Availability of more powerful, microprocessor-based protective relays, and circuit breaker with direct trip units, allowing the application of improved protection to complicated bus configurations;
— Availability of high relaying accuracy current transformers (CTs), airgap CTs, air-core sensors (Rogowski coils) and optical current sensors, which have better performance with high fault currents or have immunity to saturation not easily available with traditional iron core current transformers;
— Increased understanding of, and interest in, mitigating the arc-flash hazard.

To isolate bus faults, all power source circuits connected to the bus must be acted on by one or more of the following:

— Opened electrically by circuit breakers responding to protective-relay action;
— Direct-acting trip units on LV circuit breakers and available in some MV circuit breakers as well;
— Fuses;
— Active current limitation devices for limiting fault current consisting of conductors that are kinetically opened to shunt current to a current limiting fuse.

These disconnection devices shut down all loads and associated processes supplied by the bus and might affect other parts of the power system.

Many existing high-voltage (HV) substations are outdoor air-insulated structures enclosed by a fence where the limit of approach for a bus is established mainly via clearances. In many industrial and commercial power systems, power distribution is implemented at LV (1 kV or less) or MV (1001 V to 38 kV). MV equipment standards define MV class equipment up to a 52 kV utilization category which harmonizes IEEE equipment standards with the corresponding IEC standards. The type of equipment selected can have a great effect on the reliability, maintainability, and ease of implementation of a power system as well as the ease of implementing the required safety practices. For various applications, designers may select enclosures for buses that include, but are not limited to:

— Panelboards (UL 67 [B35]),
— Switchboards (UL 891 [B38]),
— LV motor control centers (UL 845, [B37]),
— LV power circuit breaker switchgear (UL 1558 / IEEE Std C37.20.1™),
— Metal enclosed switchgear (IEEE Std C37.20.3™), or
— Metal clad switchgear (IEEE Std C37.20.2™).

Among the various selections, the designer will find that the standards define different tests that might indicate that one type of equipment might be more suitable for a specific application than another as the tradeoffs between costs, physical size, maintenance needs, operational complexity, location, and reliability are considered. Equipment might vary with respect to the degree of bus insulation or isolation, compartmentalization, and other characteristics that impact bus reliability, safety, maintainability, or other factors.

To further reduce the occurrence of faults, the bus and associated equipment should be installed in a location where these are least subjected to extreme environmental conditions. Equipment standards such as the IEEE C37 family of standards and UL standards will define “standard conditions” and “special conditions” (IEEE Std C37.100.1™) for equipment environments. Whenever possible, equipment should be applied at standard conditions to optimize reliability and maintainability of equipment.

A preventive-maintenance program is essential to detect deterioration, to make repairs, and to check and test relays, trip units, control systems, and circuit breaker performance before a fault occurs (see IEEE Std 3007.2™ [B16]). The dielectric properties of insulating materials can deteriorate over time, particularly if the equipment is subject to greater-than-standard temperatures or transient overvoltage conditions. Moving mechanical parts can become difficult to move because of a loss of lubricity in lubricants and bonds formed at joints, and electronic capacitors can lose capacitance over time. Proper maintenance is an integral part of equipment protection, safety, and optimization of capital investments. Proper implementation of safety practices such as those described in NFPA 70E, require that maintenance of electrical equipment be properly conducted following manufacturers' instructions or generally accepted industry practices.

Modern protective relays, trip units, and control systems can measure, monitor, and calculate parameters important to implement condition-based maintenance. Modern electronic devices with appropriate communications capabilities can monitor each other as well as implement system-wide protection functions to facilitate system-wide maintenance and protection. In addition to proper maintenance, consideration should be given to including instrumentation and sensing devices or functions useful to diagnose power-system and equipment problems that might occur over the life of the equipment. Powerful multifunction digital meters, relays, and trip units are economical now. The ability to implement advanced digital communications within modern controls and protection devices allows remote control of equipment for greater safety and flexibility. Remote diagnostic capability allows experts located in remote locations to troubleshoot problems at the equipment regardless of physical location.

Regardless of the steps taken to avoid bus faults, such faults occasionally occur. High-speed protective relaying, direct acting protection (integral trip units), or appropriately rated fuses should be used to minimize fault duration. Rapid clearing times limit damage, minimize arc-flash energy, and mitigate the effects of short circuits on other parts of the power system. Providing proper bus protection requires a well-designed system. Each equipment assembly should be provided with a main protective device for each power source, either as an integral part of the assembly, or in a remote location, protecting the incoming line. In some cases, it might be advisable to install the main device in a dedicated and separate section to manually isolate the line-side bus from the source if adequate protection of the line-side bus cannot be obtained to sufficiently reduce arc-flash incident-energy values. If the main protective device is omitted in an assembly and provided by a remote line side overcurrent device, the installation may be acceptable if the device provides appropriate protection; however, the lack of a local disconnect may not be optimal for maintenance purposes. The main circuit breaker sometimes is omitted at the secondary of a power transformer when the secondary feeder breakers have ratings that adequately protect the transformer from overloading. This topology might reduce the effectiveness of secondary bus protection because the transformer reduces the sensitivity of the primary protection for secondary faults unless specific protection schemes are put in place to properly deal with the situation, like transformer differential that includes the secondary side bus within its zone of protection.

When power systems are grounded through a resistance or reactance to limit fault damage, the short-circuit current available to detect a ground fault is smaller and requires more sensitive protective relaying. A delta-wye transformer connection reflects a secondary ground fault current through two primary phase windings. The reduced value of current at the primary makes secondary ground fault currents in solidly grounded secondary transformers more difficult to detect. When the secondary of the transformer is impedance grounded, a secondary side ground fault may be indistinguishable from load for relays on the primary side and, hence, providing secondary side sensitive ground-fault relaying is important to initiate the opening of all sources that can feed the fault (see IEEE Std 242™-2001 (*IEEE Buff Book*™), Chapter 8 [B12]).[1]

When supplementary bus-differential protective relaying, zone-selective-interlocking (ZSI), or any other method is used to isolate bus faults, it is essential that the method operate only for bus and switchgear faults. False tripping on external faults is, generally, unacceptable.

[1]It should be noted that at the time of the writing of this standard, the IEEE Color Books are in the process of being replaced by the IEEE 3000 Series of standards. Hence a reference to a Color Book now may be better replaced by a reference to the appropriate IEEE 3000 Series dot standards by the reader when this standard is read. For a guide to the published IEEE 3000 Series dot standards, consult the IEEE published standards catalog.

## 1.2 Word usage

The word *shall* indicates mandatory requirements strictly to be followed in order to conform to the standard and from which no deviation is permitted (shall equals is required to).[2,3]

The word *should* indicates that among several possibilities one is recommended as particularly suitable, without mentioning or excluding others; or that a certain course of action is preferred but not necessarily required (should equals is recommended that).

The word *may* is used to indicate a course of action permissible within the limits of the standard (may equals is permitted to).

The word *can* is used for statements of possibility and capability, whether material, physical, or causal (can equals is able to).

# 2. Normative references

The following referenced documents are indispensable for the application of this document (i.e., these must be understood and used, so each referenced document is cited in text and its relationship to this document is explained). For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments or corrigenda) applies.

CSA C22.1, Canadian Electrical Code.[4]

CSA Z462, Canadian Workplace Electrical Safety Standard.

IEEE Std 3001.5™, IEEE Recommended Practice for the Application of Power Distribution Apparatus in Industrial and Commercial Power Systems.[5]

IEEE Std 3004.1™, IEEE Recommended Practice for the Application of Instrument Transformers in Industrial and Commercial Power Systems.

IEEE Std 3004.5™, IEEE Recommended Practice for the Application of Low-Voltage Circuit Breakers in Industrial and Commercial Power Systems.

IEEE Std C37.2™, IEEE Standard Electrical Power System Device Function Numbers, Acronyms, and Contact Designations.[6]

IEEE Std C37.20.1™, IEEE Standard for Metal-Enclosed Low-Voltage (1000 Vac and below, 3200 Vdc and below) Power Circuit Breaker Switchgear.

IEEE Std C37.20.2™, IEEE Standard for Metal-Clad Switchgear.

IEEE Std C37.20.3™, IEEE Standard for Metal-Enclosed Interrupter Switchgear.

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[2]The use of the word *must* is deprecated and shall not be used when stating mandatory requirements, *must* is used only to describe unavoidable situations.
[3]The use of *will* is deprecated and shall not be used when stating mandatory requirements, *will* is only used in statements of fact.
[4]CSA standards may be obtained from the Canadian Standards Association, http://www.csagroup.org/ In this document the CEC is equivalent to NFPA 70 for Canada and Z462 is equivalent to NFPA 70E for Canada.
[5]IEEE publications are available from The Institute of Electrical and Electronics Engineers, 445 Hoes Lane, Piscataway, NJ 08854, USA (http://standards.ieee.org/).
[6]ANSI device numbers are used throughout this document to represent protective relays and control elements used in electrical power system diagrams. Some of the ones used in this document are: 50-Instantaneous Overcurrent Relay, 51-Time-Overcurrent Relay, 52-Circuit Breaker, 86-Lockout Relay and 87-Differential Relay. Letters that follow the numbers such as B for bus, N for neutral, T for transformer and G for ground further identify the purpose of the device. IEEE Std C37.2 standardizes this nomenclature.

IEEE Std C37.20.7™, IEEE Guide for Testing Metal-Enclosed Switchgear Rated Up to 52 kV for Internal Arcing Faults.

IEEE Std C37.100.1™, IEEE Standard of Common Requirements for High Voltage Power Switchgear Rated Above 1000 V.

IEEE Std C37.110™, IEEE Guide for the Application of Current Transformers Used for Protective Relaying Purposes.

IEEE Std C62.22™, IEEE Guide for the Application of Metal-Oxide Surge Arresters for Alternating-Current Systems.

IEEE Std 1584™, IEEE Guide for Performing Arc-Flash Hazard Calculations.

NFPA 70, National Electrical Code® (NEC®).[7]

NFPA 70E, Standard for Electrical Safety in the Workplace.

UL 1053, Ground-Fault Sensing and Relaying Equipment.[8]

## 3. Definitions

For the purposes of this document, the following terms and definitions apply. The *IEEE Standards Dictionary Online* should be consulted for terms not defined in this clause.[9]

**air core sensors**: Also known as Rogowski coils. Specially designed air-core mutual inductor whose output voltage is proportional to the time-rate-of-change of current of the input (primary) current.

**arc-flash incident energy**: The amount of thermal energy impressed on a surface, a certain distance from the source, generated during an electrical arc event. Incident energy is measured in joules or calories per centimeter squared ($J/cm^2$ or $cal/cm^2$).[10]

**bus**: A portion of a switchgear, switchboard or distribution system that electrically interconnects several circuit breakers or switches and is protected as a separate entity from other network elements. It may also directly connect other elements such as grounding transformers, or a source transformer and the incoming compartment of distribution equipment.

**current transformers (CTs)**: A current transformer (CT) transforms line current into current values suitable for standard protective relays and meters, while isolating these instruments from line voltages. A CT has two windings, designated as primary and secondary, that are insulated from each other. (See IEEE Std 3004.1-2013.)

**high-impedance differential scheme**: A differential method of bus protection using CTs paralleled on a high-impedance load (a voltage or current relay in series with a stabilizing resistor). Throughout this text the symbol 87B inside a circle is used to indicate a differential relay in drawings. (See IEEE Std C37.234-2009.)

**high-voltage power distribution system**: A power system with nominal voltage at or above 69 kV.

[7]NFPA publications are available from Publications Sales, National Fire Protection Association, 1 Batterymarch Park, P.O. Box 9101, Quincy, MA 02269-9101, USA (http://www.nfpa.org/).
[8]UL standards are available from Global Engineering Documents, 15 Inverness Way East, Englewood, Colorado 80112, USA (http://www.global.ihs.com/).
[9]*IEEE Standards Dictionary Online* is available at: http://dictionary.ieee.org.
[10]How to calculate potential arc-flash incident energy is described in IEEE Std 1584™. The hazard this represents and implications for electrical safety are discussed in NFPA 70E.

**isolated bus (within equipment)**: Bus within distribution equipment where each phase conductor is separated from other phase conductors by insulating barriers.

**low-impedance differential scheme**: A differential method of bus protection using CTs separately connected to an electronic device that measures and vector sums the measured currents to determine differential restraint and operate currents. (See IEEE Std C37.234-2009.)

NOTE—Throughout this text, the symbol 87B inside a circle is used to indicate a differential relay in drawings.

**low-voltage power distribution system**: A power distribution system with nominal voltage of 1 kV or less.

**medium-voltage power distribution system**: A power distribution system with nominal voltage between 1001 V and 69 kV, inclusive. Traditionally in North America, medium voltage was limited to 38 kV but equipment standards have evolved to match IEC practices; hence, MV equipment standards include 52 kV today.

**zone of protection**: Divisions of protection that are logical subsections of the protection system used to isolate faulted section, i.e., generators, transformers, buses, transmission lines, distribution lines or cable circuits, and motor circuits.

NOTE—In LV and MV systems, zones may be classified as primary or backup, differential or overcurrent. Differential zones of protection are bounded by the sensing used in the differential protection scheme. Overcurrent zones of protections are bounded by the overcurrent protection device at the supply side of protected zone.

**zone selective interlocking (ZSI)**: A method used to improve the response of protective devices in the event of a fault by allowing line-side devices to react faster to faults within their zone while maintaining selectivity for faults that occur within the zone of the load-side device. ZSI utilizes a signal between a load-side overcurrent protective device and a line-side protective device to indicate that the load-side device has sensed and is reacting to an overcurrent condition. The signal is used by a line-side device to alter a corresponding protective characteristic to a slower response to allow the load-side device to clear the fault without sacrificing selectivity. (See IEEE Std 1683™-2014.)

# 4. Types of buses and arrangements

## 4.1 Construction types

There are two major types of bus: exposed and enclosed. Exposed bus is used almost exclusively in outdoor substations above 1 kV. Indoor switchboards and switchgear always have enclosed bus. Bus connecting between equipment is typically also enclosed, except in some utility vaults.

Within equipment bus protection conforms to the equipment definitions of metal-enclosed and metal-clad type equipment construction. In metal-enclosed equipment, the bus may be exposed when the external panels are removed. In metal-clad switchgear, the bus is protected within an interior grounded metal compartment. Metal-clad switchgear construction is defined by IEEE Std C37.20.2. Metal-enclosed is defined by IEEE Std C37.20.1 for equipment rated 1 kV or less and by IEEE Std C37.20.3 for equipment rated above 1 kV. UL 891 defines bus systems for switchboards rated 1000 V ac and less. Bus may also have insulation of various types applied which may provide additional electrical protection.

When determining what is appropriate protection for a bus system, it is important to understand the level and quality of the protection that bus receives. Metal barriers that isolate a bus from one compartment to another can be expected to provide some level of protection from unintended contact. Insulation can be expected to improve the dielectric reliability of the system. However, the environment, application, quality, and amount of maintenance are also concerning, regardless of the bus housing and degree or quality of insulation.

The equipment bus may have many different arrangements depending on the requirements for continuity of service for the bus and essential feeders supplied from the bus. Within any one line up of equipment there could be one or more buses. The most common arrangements are single bus radial systems with or without main devices and double ended line ups with two sources, a tie, and with mains for each source. Other more complex arrangements with dual ties in series or more than two sources are also possible. In the interest of reliability, a system designer may decide to implement a system with multiple sources in multiple enclosures with tie bus separately housed to connect the equipment where the bus associated with each source is located. This kind of arrangement lends itself well to dual ties. When a system is divided into multiple individual line ups of equipment with tie bus in between them, consideration should be given to the protection of the longer tie bus which may be more exposed than a short length of tie bus within a single piece of equipment with multiple sources. IEEE Std C37.234-2009 describes various bus schemes and associated protection zones used in MV and HV systems. The methods of protecting substation buses and switchgear might vary depending on voltage, arrangement of the buses, economic considerations, and other practical considerations.

### 4.2 Voltage ranges

North American industrial power system voltages fall into three categories:

— Greater than 52 kV
— Above 1 kV to 52 kV (in the past 38 kV instead of 52 kV was the MV to HV transition value)
— Equal to or less than 1 kV

Industrial and commercial power distribution systems may include buses at 52 kV and less. Modern large industrial complexes, however, may include distribution, sub-transmission, or transmission substation buses at a higher voltage level. IEEE Std C37.234 discusses power bus configurations and associated protection schemes for HV arrangements. Also, other IEEE standards address specific configurations where necessary. Examples of such configuration for interconnections between an industrial facility and its supply utility are also given in numerous references (e.g., Beckmann, et al. [B3]).

## 5. Zones of protection

It is critical to ensure the reliability of the protection systems including:

— Dependability: The system must operate when there is a fault (identify fault location and isolate the faulted part of the system), and
— Security and selectivity: Only the faulted power system zone is isolated, and the remainder of the power system continues its normal operations.

Zones may have defined demarcation (e.g., transformer differential protection). Protection may be defined as primary and back up protection as established by time-current coordination (overcurrent thresholds) or other protection methods. Zones of protection can be identified by the sensor locations that define the zone within which a fault might be detected, or by the controlled switching elements that can clear the fault once it is detected. When multiple sensors are used for the various types of protection, proper location of the sensors can ensure that blind spots are minimized. When using the same sensor for multiple functions or using sensors located within the switching devices (such as in LV circuit breakers), it is important to understand that blind spots might be created and these need to be assessed. If multiple sensors are used and they can be dedicated to different protective functions and zones, then the systems designer should strive to achieve overlapping zones of protection that eliminate blind spots. However, excessive overlap can negatively impact system reliability as well.

Figure 1 shows a simple radial substation with a single source. In this example, differential protection is applied using dedicated CTs that are arranged so that the differential-protection zone and overcurrent-protection overlap, and the entire bus is protected. Figure 2 shows the same substation bus protection, but only one set of CTs is used. Here, there is no overlap. However, for a simple topology in medium and low voltage, protection is provided by either scheme. In a system with networked sources, CT location can create short spots that are outside of the faster protection zone, or that are inside multiple protection zones, and can cause mal-operation of the protection system. For a more thorough discussion of network applications, see 5.1 of IEEE Std C37.234-2009.

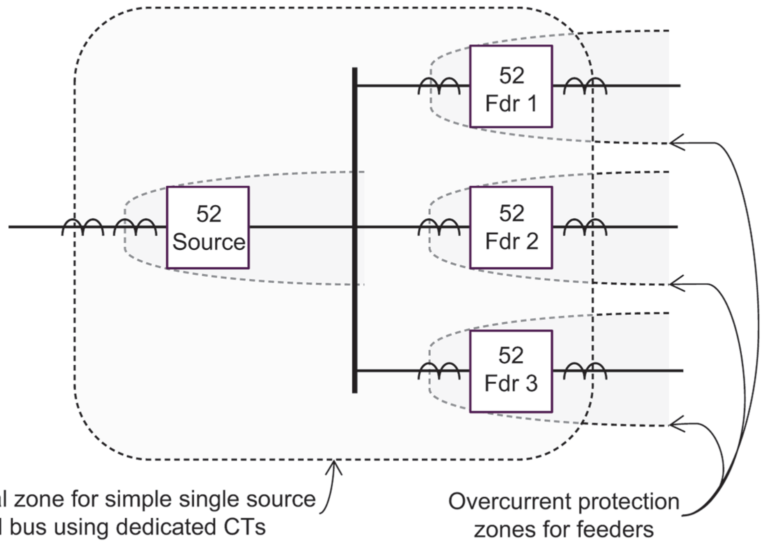



**Figure 1—Simple single-source radial substation**

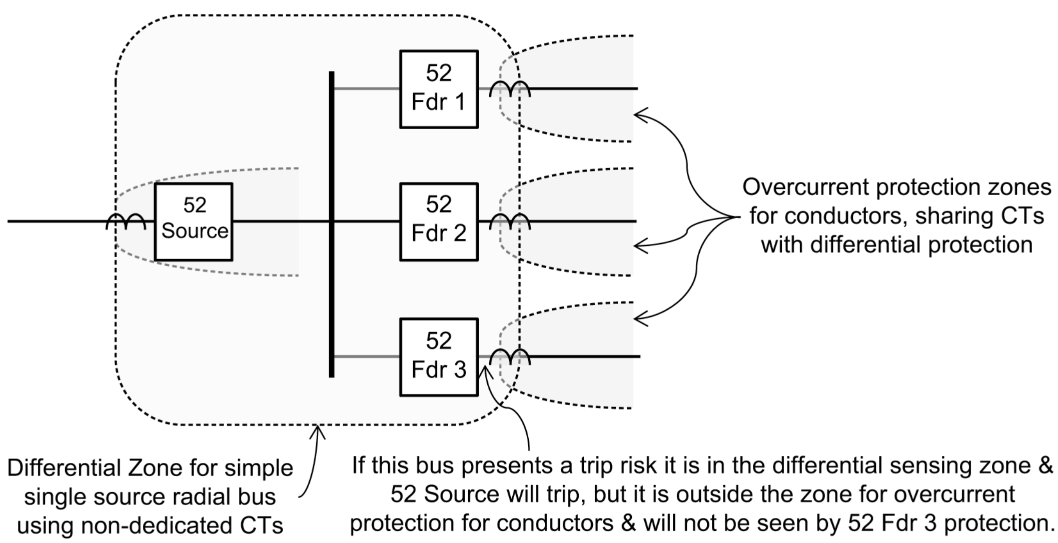



**Figure 2—Simple single-source radial substation using one set of CTs**

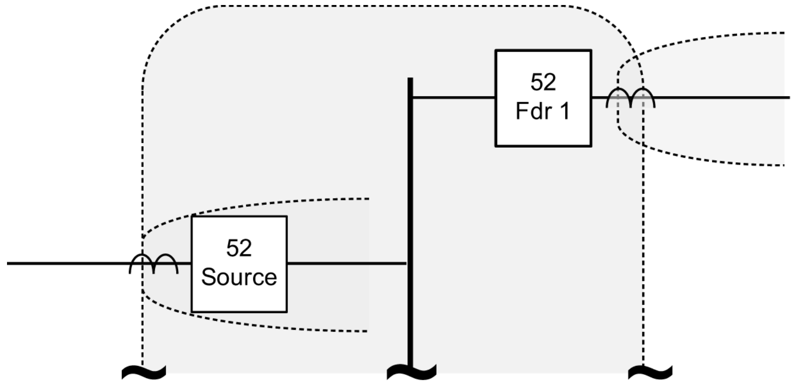



**Figure 3—CT location reference diagram**

For the purposes of this standard, protection zones related to a CT are drawn so that the CT is included in the pertinent zone. A CT circuit may have a fault within the bus that is measured by the CT; in that case, the measurement will contribute to detection in both differential and overcurrent zones. If the fault is such that the CT undermeasures, it may contribute to a differential zone but may not be detected by an overcurrent zone.

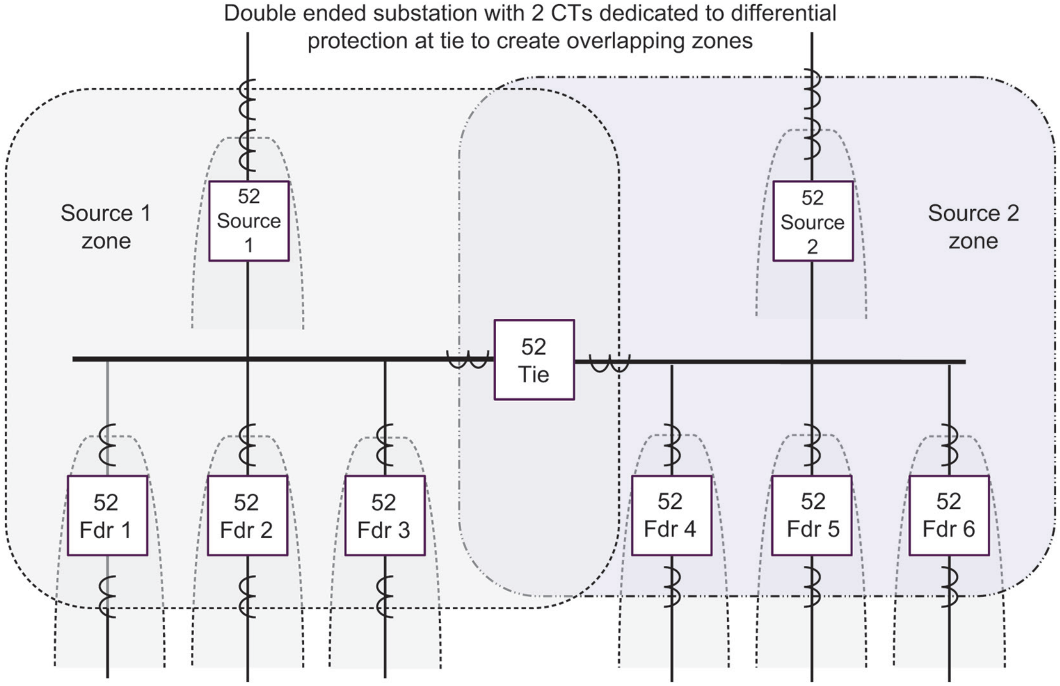



**Figure 4—Double-ended substation, single tie, with dedicated CTs for the two differential zones**

Figure 4 illustrates a typical design for systems with multiple sources and tie circuit breaker(s). Differential zones should overlap so that no bus sections are left without fast differential protection.

## 5.1 Double-ended substations with two tie CB in series

Some double-ended substations are implemented with two ties connected in series, and working together, for various reasons. The most common reasons are:

- To isolate a tie bus or connection that is considered to have a realistic probability of failure;
- To help ensure complete isolation of the buses from each other for maintenance activities and safety.

There are multiple ways to implement differential protection in such a scheme. Two or three differential zones may be created. The tie bus may be included in different ways depending which tie the differential zone controls and the location of the CTs associated with the ties. Table 1 shows five ways to locate CTs and implement bus differential protection in two-source dual-tie schemes. Selecting the method that is most applicable to a situation will depend on:

- The location of the realistic probabilities of failure;
- The available space for CTs;
- The type of differential relay being considered;
- The level of complexity or cost that is acceptable for the application.

In these schemes, faults that occur on the main part of the load buses are well protected with proper selectivity. However, the system reaction to faults near the tie circuit breakers or in the tie interconnection can vary with each scheme.

In the first scheme described in Table 1 and shown in Figure 5, two differential zones are implemented. Each bus differential relay will open both ties which means any fault sensed anywhere in the buses will separate the sources. This is acceptable when sources are operating in parallel or when the fault is on the distant bus when only one source is connected. However, if the fault is in the tie bus between the tie CTs (fault 3), then both sources will be taken off line. A fault within the tie bus not located between the CTs (fault 2 and fault 4) will cause one source to open and both ties to open, isolating the fault, but unnecessarily disconnecting one of the main buses. Hence, if it is perceived that fault locations 2, 3, and 4 are where faults could happen, this may not be a good scheme from a reliability perspective; however, it is a good scheme from a protection perspective. An interlocking scheme using logic from one or both relays may be implemented to prevent operation of the main CBs and operate only the tie circuit breakers when both differential zones sense differential faults simultaneously, which occurs when a fault is in the overlapping zone. This may be considered if a fault in location 3 is more probable than a fault in location 2 or location 4.

In the second scheme described in Table 1 and shown in Figure 6, two differential zones are implemented. Each bus differential relay operates one tie circuit breaker. One of the sets of tie-CTs is located within the tie bus and the other CT set is located within one of the main buses. In this scheme, bus fault locations 3 and 4 are on the tie interconnection. If a fault happens at location 3, both zones will sense the fault, causing both ties and both sources to open, fully isolating the fault, but also removing both sources from both load buses. If the fault is at fault location 4, only one source and one tie will open, isolating the fault location from only one source. If the other tie is closed and that source is connected, the fault may not be fully isolated. Also, the connected load will be dropped because of the one main CB opening and isolate the main bus.

The third scheme, described in Table 1 and shown in Figure 7, is similar to the second, but the controlled tie CBs are the more remote from the main CBs. This scheme is an improvement from the second in that a fault in location 3 or location 4 will be isolated from both sources. However, a fault in location 3 will also isolate both main load buses, and one in location 4 will clear one load bus.

In the fourth scheme described in Table 1 and shown in Figure 8, CTs associated with the tie circuit breakers are located on the main load buses and overlap. The tie interconnection is within both zones so a fault in fault locations 2, 3, and 4 will cause both ties and both load buses to be isolated from sources. An interlocking scheme using logic from one or both relays may be implemented that operates only the tie circuit breakers when both differential zones sense differential faults simultaneously, which occurs when a fault is located in the overlapping zone. This may be considered if a fault in location 3 is more probable than a fault in location 2 or location 4.

In the fifth scheme described in Table 1 and shown Figure 9, four sets of CTs associated with the tie CB are used. Tie bus faults are always selectively isolated. However, faults at location 2 and location 4 can still unnecessarily clear a load bus. If faults at locations 1 and 5 are deemed improbable, it may be advisable to implement a logic scheme that prevents the main bus protection differential from tripping the main CBs for a set delay if the tie differential protection is opening the tie CB. That may improve reliability but may delay protection if a fault occurs at location 1 or 5. Generally when using bus differential, the intent and expectation is fast bus protection. Delaying the opening of a source CB is not normal practice and should be carefully considered if contemplated as it significantly limits the benefit associated with bus differential protection.

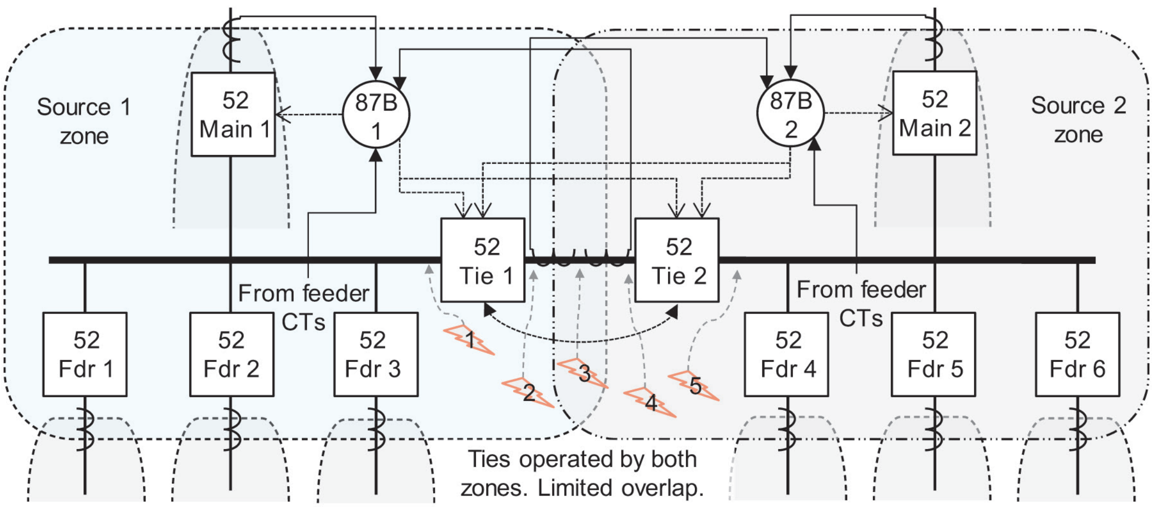
These examples demonstrate that there is no single perfect implementation of differential protection in sources with multiple sources and multiple ties in series. What is optimal for a situation will depend on various factors including perception of the most probable fault locations and the need for reliability. In addition to differential protection, interlocking logic can further improve a scheme to ensure minimum interruption of power to served loads.

The main overcurrent protection can be used as a backup to the ties in case the tie circuit breakers fail to isolate the fault. Modern digital protective relays have capabilities for providing this, and the best way may vary based on the exact relay used and degree of complexity deemed acceptable. Protective relay manufacturers should be consulted on the best method suitable for the given situation and specific product recommendations. These methods should not require delays long enough to allow another CB to open, i.e., more than three to six cycles. As with any protection solution, the complexity needs to be weighed against the reliability risks associated with the complexity.

The feeder overcurrent protection might allow a portion of conductors inside the CBs to be protected by the differential protection instead of the feeder overcurrent protection (as Figure 3 and Figure 4 imply). A fault internal to the circuit breaker would be a very serious event in the main equipment. Therefore, it may be acceptable to allow the lack of selectivity created by the differential zone instead of simply allowing the feeder overcurrent-zone to provide the protection at delays required for selective operation of the system.

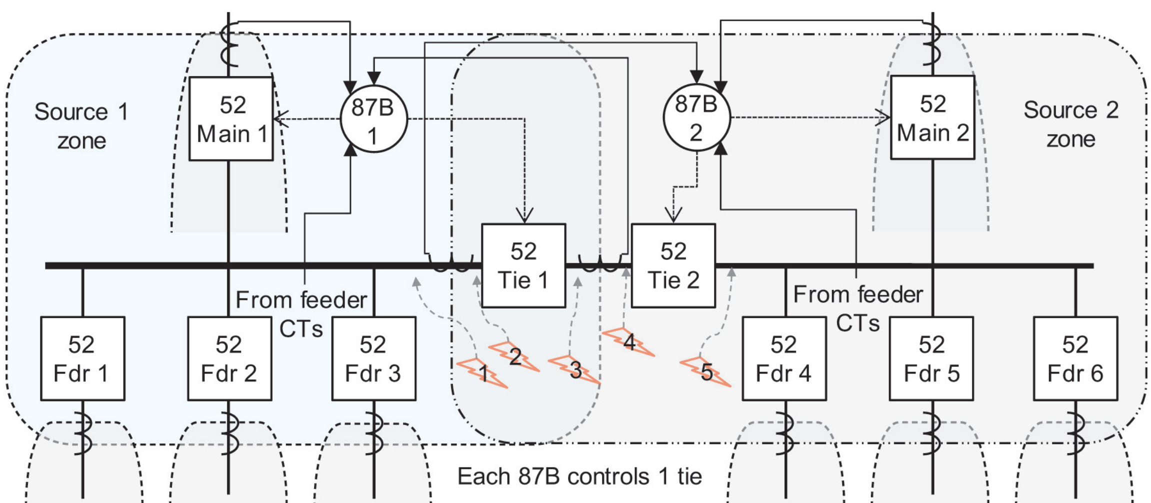
**Table 1—Dual tie substation with bus differential implementation alternatives**

| Figure | Substation | Fault | M1 | T1 | M2 | T2 | Bus 1 | Bus 2 | Tie Bus | Fault cleared |
|---|---|---|---|---|---|---|---|---|---|---|
| 5 | **2 CTs between ties** | 1 | Open | Open | Unaffected | Open | Cleared | Unaffected | N/A | Yes |
| | | 2 | Open | Open | Unaffected | Open | Deenergized | Unaffected | Cleared | Yes |
| | | 3 | Open | Open | Open | Open | Deenergized | Deenergized | Cleared | Yes |
| | | 4 | Unaffected | Open | Open | Open | Unaffected | Deenergized | Cleared | Yes |
| | | 5 | Unaffected | Open | Open | Open | Unaffected | Cleared | N/A | Yes |
| 6 | **2 CTs around 1 tie, zone control near tie** | 1 | Open | Open | Unaffected | Unaffected | Cleared | Unaffected | N/A | Yes |
| | | 2 | Open | Open | Open | Open | Cleared | Deenergized | N/A | Yes |
| | | 3 | Open | Open | Open | Open | Deenergized | Deenergized | Cleared | Yes |
| | | 4 | Unaffected | Unaffected | Open | Open | Unaffected | Deenergized | Not cleared | No |
| | | 5 | Unaffected | Unaffected | Open | Open | Unaffected | Cleared | N/A | Yes |
| 7 | **2 CTs around 1 tie, zone control far tie** | 1 | Open | Open | Unaffected | Unaffected | Cleared | Unaffected | N/A | Yes |
| | | 2 | Open | Open | Open | Open | Cleared | Deenergized | N/A | Yes |
| | | 3 | Open | Open | Open | Open | Deenergized | Deenergized | Cleared | Yes |
| | | 4 | Unaffected | Unaffected | Open | Open | Unaffected | Deenergized | Cleared | Yes |
| | | 5 | Unaffected | Unaffected | Open | Open | Unaffected | Cleared | N/A | Yes |
| 8 | **2 CTs outside both ties, with 3rd zone logic or summation** | 1 | Open | Open | Unaffected | Unaffected | Cleared | Unaffected | N/A | Yes |
| | | 2 | Unaffected | Open | Unaffected | Open | Not cleared | Deenergized | N/A | Yes |
| | | 3 | Unaffected | Open | Unaffected | Open | Unaffected | Unaffected | Cleared | Yes |
| | | 4 | Unaffected | Open | Unaffected | Open | Deenergized | Not cleared | N/A | Yes |
| | | 5 | Unaffected | Unaffected | Open | Open | Unaffected | Cleared | N/A | Yes |
| 9 | **4 tie CTs external and internal to tie bus** | 1 | Open | Open | Unaffected | Open | Cleared | Unaffected | N/A | Yes |
| | | 2 | Open | Open | Unaffected | Open | Deenergized | Unaffected | Cleared | Yes |
| | | 3 | Unaffected | Open | Unaffected | Open | Unaffected | Unaffected | Cleared | Yes |
| | | 4 | Unaffected | Open | Open | Open | Unaffected | Deenergized | Cleared | Yes |
| | | 5 | Unaffected | Open | Open | Open | Unaffected | Cleared | N/A | Yes |



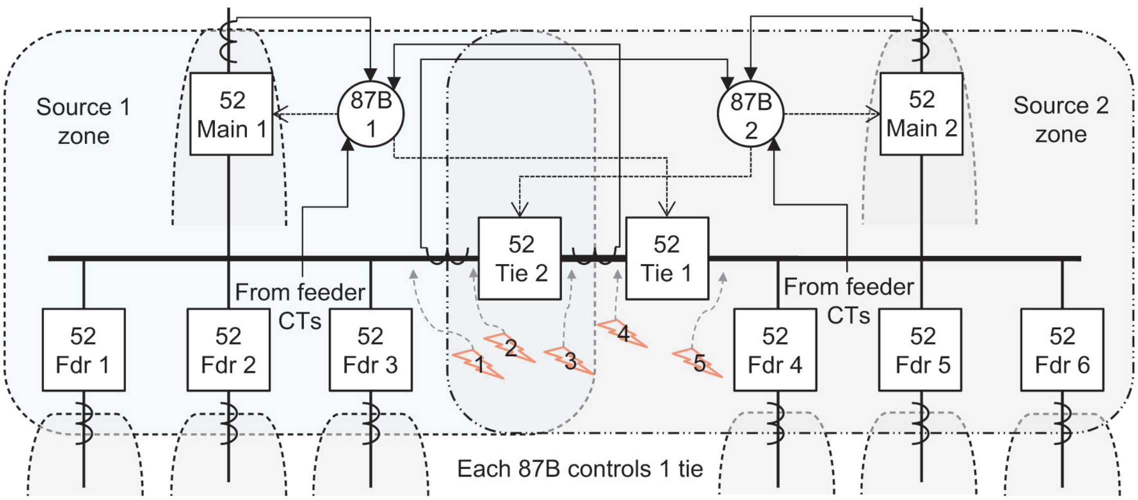

- bus faults always cleared → Yes,
- tie faults always cleared → Yes,
- degree of unnecessary overlap → depends on bus length between physical CT locations,
- wiring control complexity → higher,
- relay type → suitable for separate HZ or LZ relays.

**Figure 5—Double ended substation with 2 ties and 1 CT set per tie CB with minimum tie zone overlap**



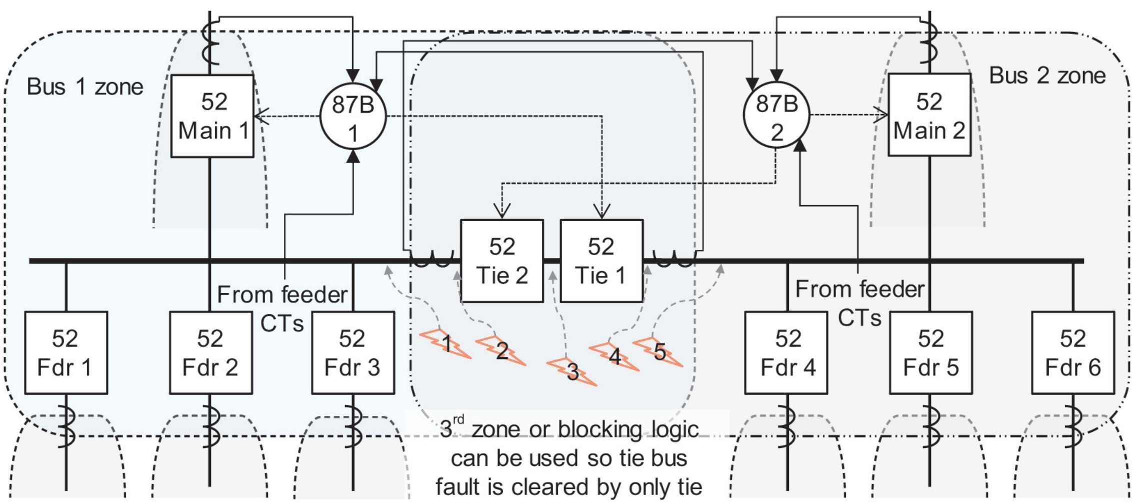

- bus faults always cleared → Yes,
- tie faults always cleared → No,
- degree of unnecessary overlap → depends on length of bus between CT1 & tie 1,
- wiring control complexity → simpler,
- relay type → suitable for separate HZ or LZ relays.

**Figure 6——Double ended substation with 2 ties and 1 CT set per CB; 1 tie in each zone**




- bus faults always cleared → Yes,
- tie faults always cleared → Yes,
- degree of unnecessary overlap → depends on length of bus between CT1 & tie 2,
- wiring control complexity → simpler,
- relay type → suitable for separate HZ or LZ relays.

**Figure 7—Double ended substation with 2 ties and 1 CT set per CB; 1 tie in each zone**




- bus faults always cleared → No,
- tie faults always cleared → Yes,
- degree of unnecessary overlap → depends on bus length between CT & corresponding CB, usually short,
- wiring control complexity → simpler but more complex relay logic,
- relay type → suitable for multiple element LZ relays with logic capability,
- substation layout → specially suitable for long exposed tie bus.

**Figure 8——A double ended substation with 2 ties and 1 CT set per CB; full tie bus overlap**

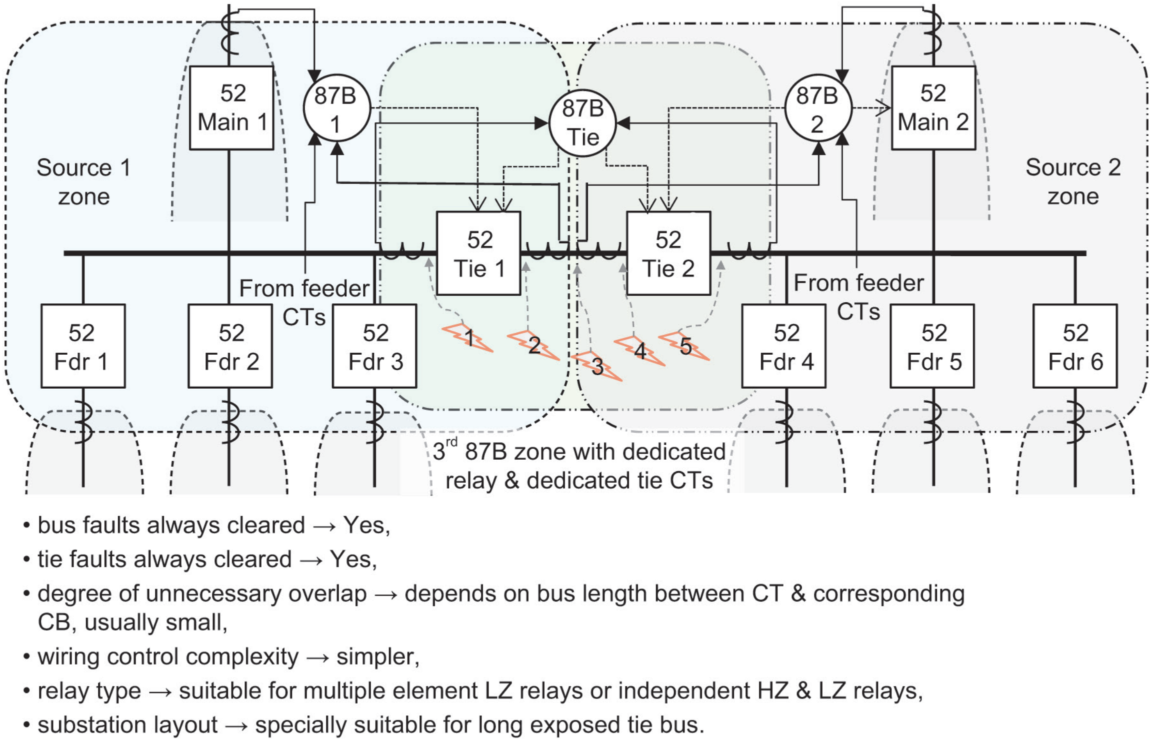



**Figure 9—Double ended substation with 2 ties and 2 CT sets per tie CB; full tie bus overlap**

## 6. The need for fast bus protection

As part of the overall industrial and commercial power distribution systems, buses are protected by primary and back up overcurrent devices. Traditional bus overcurrent protection devices are required to coordinate with branch and feeder overcurrent devices, resulting in slower bus protection. In many cases, it is important that bus protection has quick operating characteristics. Such fast bus protection can be important to the entire power distribution system and positively affect overall system reliability.

Equipment can be damaged by three fault-current-caused effects:

— Large magnetic forces in some systems are severe during the first few fault cycles and can tear the bus from its attachment points and bend rigid conductors. These effects create additional fault points and can whip flexible conductors, damaging the conductors and nearby equipment along the path of fault current from source to fault;

— The $I^2t$ heating effect created over time by excessive current can deteriorate insulation and even result in softening and melting of conductors along the current path;

— Arcing at the point where the fault occurs can be very damaging, causing melting, burning, and contamination that can damage nearby equipment as well.

In addition, it is not unusual for operating personnel to be near important equipment containing high-energy buses. Personnel might be engaged in operating circuit breakers, racking circuit breakers in and out. They might be engaged in other operation or maintenance activity on buses, device control wiring, instrumentation, and other portions of the distribution, control, and metering system. An arcing fault exposes nearby personnel to arc-flash related injuries, and fast protection is very important.

Fast protection in the case of an in-equipment arcing fault can reduce the incident heat energy released by the arc. This in turn can also reduce the arc-flash protection boundary around the equipment and reduce the likelihood of the blast effects that could be created by the arc. In addition to lessening the personnel injury aspects of arc flash, fast clearing times will also reduce fault damage to the equipment.

The improved safety provided to personnel by fast, sensitive protection can also have significant value in terms of productivity and reliability, such as reducing:

— The time to recover from a fault event;
— The cost of equipment replacement;
— The cost of providing access to major electrical equipment for replacement;
— Production time lost due to incident investigation;

Therefore, when considering whether to add the cost and complexity of fast bus protection it is important to consider the following:

— How the equipment will be operated and maintained;
— The consequences of a fault within the equipment;
— The best possible protection that can be afforded to reduce hazards to personnel as well as reducing damage to equipment wherever it is required or practicable.

Fast-bus transfer schemes should be considered as a part of the protection solution when multiple sources are available and maintaining power to loads is important for reliability or safety. However, if the bus itself is faulted, then transfer between multiple sources must be blocked. Such schemes are further discussed in 6.11 of IEEE Std 3004.8.

# 7. Bus overcurrent protection

## 7.1 General discussion

Many industrial and commercial power distribution systems are radial, and overcurrent protection is used for both the incoming power-source circuit and the branch feeders. The incoming power source protection can also provide bus protection. The incoming power source circuit and bus overcurrent protection is often required to coordinate with the branch feeder protection resulting in a slower bus protection. Whether the protection is adequate would depend on the assessed probability of a fault event, the effect of the event on the system, effect on the mission of the system, estimated time to repair damage, and the risk of injury to personnel. Considerations for the ability to sustain loads appropriately and desired coordination of protective devices can degrade the protection that simple overcurrent protection can provide. When simple overcurrent protection is not capable of obtaining desirable protective and selectivity performance goals, the various techniques described in this recommended practice should be considered.

To achieve selective coordination, overcurrent relays and trip units may have delay settings and high-current setting ranges to delay opening the source circuit breakers upon the occurrence of a feeder fault. This is not uncommon in industrial systems that require selective systems to ensure system reliability. Presently, systems covered by the NEC's definition of Emergency (section 700, NEC), Legally Required Standby Systems (section 701, NEC) or Critical-Operations-Power systems (section 708, NEC) also require selective performance. For such systems, the NEC requires complete selectivity, called selective coordination in the NEC, from the branch overcurrent protective device to the emergency power source and for the normal power source. The NEC mandate requires instantaneous protection, if present, to be selective. The extent to which protection system selectivity applies depends on the revision of the NEC that has been adopted

by the jurisdiction and how these requirements of that revision are interpreted by the jurisdiction. Systems designed for selective coordination might not provide sensitive, high-speed bus and switchgear protection unless designs, components, or protective schemes are specifically selected to provide high-speed protection and selective coordination simultaneously in the fault current range of interest. See Valdes et al. [B41] and [B43] for further reading.

On MV and HV systems, fuses, overcurrent relays, and arc-flash relays that trip circuit breakers are often used for 3-phase fault and inter-phase fault protection where fault currents are typically high and overcurrent protection can be effective. These systems are supplemented with sensitive ground relays when the system is low-resistance-grounded (MV) and with ground-fault detection in high-impedance grounded systems (LV and MV). In LV, high-impedance-grounded systems, ground-fault detection systems are required to annunciate the occurrence of a ground fault when tripping is not immediately initiated. Systems that identify fault location are desirable to facilitate rapid and safer troubleshooting and to expedite the removal of an accidental ground-fault. Chapter 4 and Chapter 8 of IEEE Std 242-2001 (*IEEE Buff Book*™) provide details on relays and procedures for proper settings. Modern switchgear standards also allow for MV circuit breakers with built-in, direct-acting trip units that might incorporate GF detection and protection.

On LV systems, most applications use circuit breakers or fuses. Electronic trip units for LV circuit breakers perform the sensing and timing functions that provide required protection for LV circuits and apparatus. Modern LV trip units implement protection, metering, communications, and logic capabilities that are very capable. The selectivity and protection clearing time possible with LV integral trips often exceeds the capabilities possible with component relays operating those same LV circuit breakers. IEEE Std 3004.5 describes how to select and apply LV circuit breakers. IEEE P3004.3/D1b-2017 covers LV fuse application.

Differential protection of LV buses presents additional challenges to similar protection in MV and HV buses (see Valdes et al. [B45]). In LV buses, fault currents may be high multiples of load current, while arcing faults may be significantly lower magnitude than maximum calculated bolted-faults. However, working distances are shorter, hence incident arc-flash energy per unit time may be high causing every millisecond that protection is accelerated to be important. For that reason, implementation of differential protection may be desirable, but traditional methods may be difficult, expensive, or too space consuming to be practical. Techniques such as combining partial differential with zone-selective-interlocking, using differential protection integral to the LV protection, or implementing zone-selective interlocking or other manufacturer-specific techniques may be valuable in providing improved protection in a more practical manner.

The suitability of the protection afforded to LV equipment depends partly on the type of equipment containing the bus and the standards around which that equipment is designed, manufactured, and tested. When the feeder circuit breaker clearing time, fed from a bus, exceeds three cycles, the bus in the equipment should have adequate withstand rating to prevent subsequent internal damage during the time that a through fault might last (before being cleared by the feeder device in the equipment). LV power-circuit-breaker switchgear (UL 1558, IEEE Std C37.20.1) is furnished with a 30-cycle rated bus per the requirements of the standard. Protection should not require 30 cycles to clear a large-magnitude fault. UL 891-listed switchboards normally available with a 3-cycle withstand rating may be available with optional 30-cycle rated bus based on testing performed by the manufacturer over and above that required by the UL standard for that equipment. When using protective relays in LV equipment, extreme care should be taken to ensure that clearing times do not exceed equipment or circuit breaker withstand capabilities. Integral circuit breaker trips are designed to not allow the circuit breaker or equipment withstand capabilities to be exceeded; hence, even if protective relays are implemented, the integral trips should not be removed. Distribution equipment that has branches that always have instantaneous protection, such as LV MCC, are not required, by applicable standards, to have significant withstand ratings as any significant through fault will be interrupted by the instantaneous protection in the feeders.

When considering arc-resistant equipment (ANSI/IEEE Std C37.20.7), it is important to ensure that the protection for all buses and conductors within the equipment protects the buses within the identified arc-resistant withstand time identified by the manufacturer for the arc-resistant equipment. This might be difficult, and therefore requires special attention when the line-side conductors of equipment fed by a step-down

transformer are protected by a device on the line side of the transformer. See Mello et al. [B24], Simpson [B33], and Valdes et al. [B41] for further reading.

Implementation of fast digital communications networks, such as that defined by the IEC 61850 [B39] set of standards, in LV and MV protective devices, allows both distributed and central processing of current, voltage, and device data. Fast digital communication facilitates fast, sophisticated protection that can accommodate changes in system topology and can identify the fault location within the equipment, optimizing protection as required by the actual topology in place at the time of the fault. For further reading on use of IEC 61850 in MV and HV applications, see Apostolov et al. [B1] and [B2], and for an example of an LV application, see Valdes et al. [B44].

LV bus protection tends to rely on the direct-acting integral trip units provided with circuit breakers tested and listed as a system that includes the circuit-breaker mechanism and the integral trip unit. The trip unit is not only designed to provide the proper protection adjustability that might be suitable for a range of connected loads, it is also designed to protect the circuit breaker from being applied above its withstand capabilities. LV power circuit breakers (LVPCB) are also UL listed (UL 1066 [B40]) for use with separate protection relaying. LV, circuit-breaker direct-acting trip units provide most of the protective functions even when self-powered from fault current. It is not recommended that a LVPCB be used without its integral trip unit even if additional protective functions are implemented via separate protective relaying such as differential or overcurrent relays. When operating LVPCB from external relays, such as an arc-flash relay, it is important to consider the additional operating time that a shunt-trip coil might add versus the usually faster, internal, flux-shifter coil that the direct-acting trip unit might use. Manufacturers should be consulted to ensure that the operating time and clearing time of the circuit breaker and all auxiliary devices are included.

To reduce the possibility of destructive arcing faults, phase or ground, on 480Y/277 V and 600/347 V systems, and to lessen the shock hazard when enclosure rear covers are open, the LV bus can be provided with an insulating cover. This is generally available as an option on LV power switchgear and might be available on some switchboard designs, particularly those with individually mounted devices and rear access to cable terminations. Front-access switchboards have very limited capabilities for insulated bus coverings. It is not usually available in panelboards.

Insulated and/or isolated bus may be available as an option on MV, metal-enclosed switchgear (IEEE Std C37.20.3), MV motor control (ANSI/UL 347 [B36]), on LV switchgear (IEEE Std C37.20.1), LV motor control centers (UL 845, [B37]), and on switchboards (UL 891 [B38]). Insulated bus is mandatory in metal-clad switchgear (IEEE Std C37.20.2).

## 7.2 Low-voltage (LV) bus ground-fault protection for solidly grounded systems

Electronic trip units in circuit breakers are available with integral residually connected phase sensors and may implement an external neutral sensor, if required. Some circuit breakers and switches (UL 977 [B39]) might also use external zero-sequence sensing and process the signal within the device to generate a trip. Separate ground-fault relays using zero sequence sensing are also commonly applied and trip the circuit breaker via a shunt trip device. The 2017 NEC® (NFPA 70) requires ground-fault protection on solidly grounded, wye-connected electric services of more than 150 V to ground, and not exceeding 1 kV phase to phase, for the following devices:

a) Any service disconnecting means rated 1000 A or more (see 230.95);

b) Any feeder-disconnect rated 1000 A or more (see 215.10);

c) Each building or structure main disconnecting means rated 1000 A or more (see 240.13).

The NEC (230.95 for services, 215.10 for feeders, and 210.13 for branch circuit devices) states that GF protection must be provided in certain applications and that the maximum pickup setting for the ground fault

function (or sensor) is 1200 A. A GF function with a deliberate time-delay characteristic must trip within 1 s for currents equal to or greater than 3000 A. It also states that this requirement does not apply in certain applications (such as continuous processes where interruption would be more hazardous than the ground fault itself). It should be noted that in many situations there is not a given standard that determines practice but the interpretation of that standard by the local inspector (Authority Having Jurisdiction). UL 1053 also defines an additional point on the ground-fault curve at 150% of the nominal pickup setting that must not exceed 2 s clearing time. Figure 10 shows an example of an LV ground-fault protection curve and the various NEC-required limits. NEMA PB2.2 [B27] also provides guidelines for interconnecting LV ground-fault protection in complex systems as well as recommendations for assessment of acceptable bus damage in the case of a low-magnitude, single-phase, arcing ground fault. Ground-fault protection in systems with multiple sources is complex. Different manufacturers employ different schemes to achieve proper protection in complex systems. Some are more suitable for open-transition systems, others for closed-transition systems. For further details, see IEEE Std 242-2001 (*IEEE Buff Book*™)[11] Chapter 8 and NEMA PB2.2, as well as manufacturers' application guidelines.

Where main service-entrance circuit-breakers rated 1000 A or more are required to have ground-fault protection in solidly grounded systems, achieving selective coordination requires coordination of the ground-fault device with load-side phase protection (provided by circuit breakers or fuses). Selective coordination can be achieved using delays, nested pickup thresholds, and careful selection of device response curve where alternatives exist. Protection can be enhanced using zone-selective interlocking. Bus-differential protection can also be set sufficiently sensitive to provide ground-fault protection in some cases. However, achieving selective coordination for ground faults between line-side ground-fault relays and load-side phase protection might be very difficult because of the limited flexibility in ground-fault device curve shape and pick up settings that are allowed by the applicable standards. See Figure 10.

[11]See footnote 5.

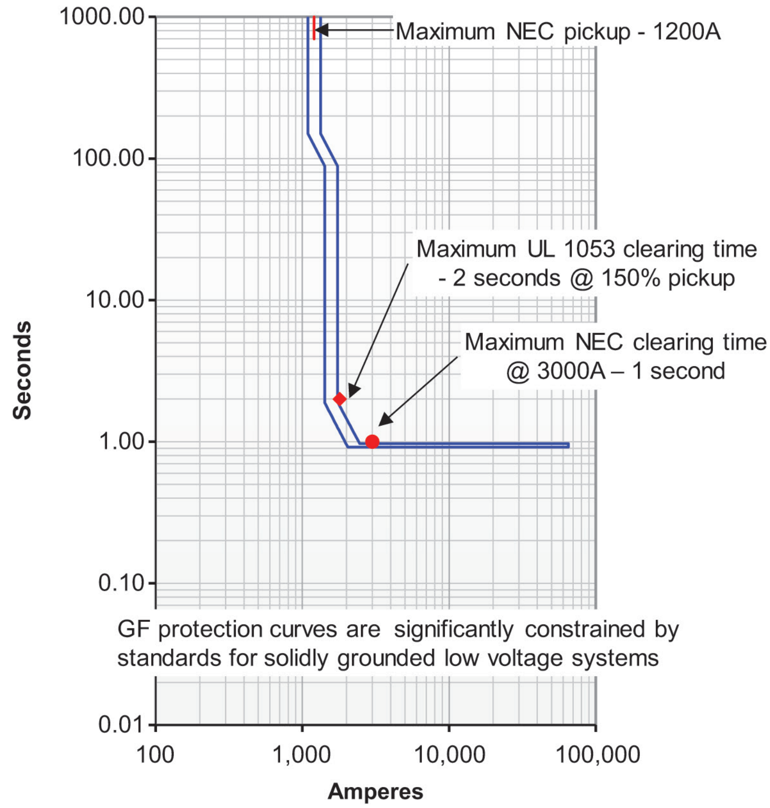



**Figure 10—Required maximum characteristic points for low-voltage, ground-fault protection**

## 7.3 Ground-fault protection on LV ungrounded or impedance grounded buses

Ungrounded systems are selected to improve system reliability as a first ground fault does not require isolation of the faulted circuit. Ungrounded systems are rare in modern land-based systems, though common in shipboard applications. The 2017 NEC requires ground-fault detectors for ungrounded systems in sections 250.36 (2) and 250.187(2). Impedance grounded systems for LV are typically high resistance grounded (HRG) systems. High resistance grounded systems may also be considered to increase safety as a single unplanned connection between live conductors and the ground plane does not escalate to an arc flash or fault event. HRG systems are rarely designed with tripping on the first ground fault (GF). However, they are designed with varying levels of GF detection systems.

Though the NEC requires only a single level of GF detection and tripping based on the detected GF is not required, consideration should be given to the implications of meeting only the minimum requirements in the NEC for GF fault indication on LV HRG systems. Not correcting a first ground creates the possibility that a high-current phase-to-phase fault will occur between two circuit breakers if a second ground fault on a different phase of the system happens before the first GF is removed. When two GFs exist simultaneously, the resulting phase-to-phase fault may result in the loss of multiple circuits. Various systems for detecting grounded circuits in HRG systems at load-side circuits exist today. These systems can be used to facilitate trouble shooting of ground faults for more efficient and safer removal. Use of load-side GF detection in LV HRG systems is recommended. GF detection on an HRG system could be based on voltage or current sensing. Sensing and indication may be as basic as simply indicating a fault on the system exists to increasing levels of information detail such as identifying which phase is grounded, which main equipment feeder, or even which branch circuit overcurrent device is feeding the fault circuit. Detail level detection is advised to improve maintainability, safety, and reliability. In some cases, LV switchgear or overcurrent devices such as electronic

overloads may have built-in detection to facilitate such detail location identification and relays systems to implement such detection is available. To prevent a fault from persisting too long and eventually resulting in a dangerous multiple phase fault, consideration should be given to alarming that is difficult to go unnoticed. Consideration should be given to tripping overcurrent devices even if it is days after having first alarmed a persistent GF. Ground-fault protection in LV systems is discussed further in IEEE Std 142 (*IEEE Green Book*™) [B11].

### 7.4 Medium-voltage (MV) and high-voltage (HV) bus ground-fault protection

In MV and HV solidly grounded systems, ground-fault protection can be implemented using various means:

— When supplied by a user-owned transformer or generator, an inverse-time or definite-time overcurrent relay connected to a current transformer in the source neutral-to-ground circuit provides good sensitivity for ground faults (including ground faults within the windings of the transformer secondary winding or generator stator winding).

— On switchgear where the owner does not have access to the transformer neutral connection, residually connected ground-fault relays or relays that calculate neutral current from the vector sum of the phase currents may be used. Ground sensor relays in large systems implemented with iron core sensors (zero-sequence sensors) may not be practical because the ground sensor windows large enough to allow all the power cables to pass through may not be available and zero-sequence CTs may pose saturation problems. Rogowski coils (air core sensors) may be an alternative as they do not pose saturation concerns. Digital relays can implement GF protection with residual schemes without the need to install zero-sequence sensors.

The main, or incomer's, ground-fault relaying should be set to be selective with overcurrent relaying on load-side feeders, if possible. A feeder ground fault of sufficient magnitude will be sensed as a phase fault by the feeder overcurrent relay and as a ground fault by the main incomer's GF relaying. Inverse-time overcurrent relays, without instantaneous elements, are commonly used. If the feeders have ground-sensor instantaneous protection, faster time-overcurrent delays are possible.

Because most faults are ground faults, or eventually become ground faults, ground-fault protection greatly improves bus overcurrent protection. Additional descriptions and guidance on ground-fault protection can be found in IEEE Std 242 (*IEEE Buff Book*™) [B12].

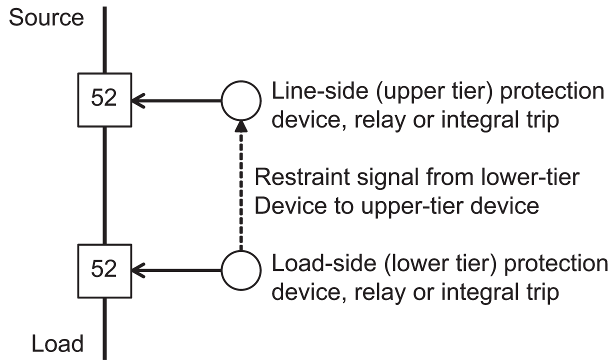
## 8. Zone-selective interlocking and blocking techniques

### 8.1 General discussion

A common method used in LV protection to improve protection speed is known as zone-selective interlocking (ZSI). Component relays commonly used in MV systems may also implement blocking schemes that operate similarly but allow for more customization by users. In the simplest terms, ZSI is the ability of a lower tier (load-side) protective device that has sensed current that exceeds a set threshold to signal to upper tier device(s) (line-side), via a restraint signal, that the fault has been detected and will be acted upon by the lower tier device; thus, the upper tier device(s) can operate in a restrained protective mode to allow the load-side device to operate (see Figure 11).

These schemes are described in 7.2 of IEEE Std C37.234-2009. The primary advantage of zone-selective interlocking is its ability to provide faster fault clearing for bus faults without sacrificing system selectivity with feeder protection fed by the bus. ZSI is an economical alternative to bus differential protection and may provide a suitable alternative in those situations where CT saturation makes differential schemes impractical. ZSI might provide less sensitive, or slower protection than differential relays. Also, while differential systems are inherently selective for through faults, ZSI systems are not. The lowest tier overcurrent device in a ZSI

scheme must be coordinated with load-side devices not included in the ZSI system. Zone-selective interlocking is particularly suited for circuit breakers with integral trip units commonly provided with LV circuit breakers. ZSI is beneficial even in MV circuit breakers with relays and separate CTs. It is less demanding on CT accuracy relative to differential-protection schemes. The ZSI restraint signal sent from one tier to another is commonly conveyed over a dedicated control circuit. On systems using protective relays, the signal could also be conveyed using serial communications, particularly those designed following IEC 61850 standards.




The restraint signal is a logical input into line-side device control logic. The line-side device may alters its protection response in a number of ways based on the receipt of the restraint signal. In protective relays the response may be fully user programable. In LV trips the response will be constrained by the behavior programed by the trip unit manufacturer but will allow for needed user selections and settings to maintain selectivity and improve protection.

**Figure 11—ZSI scheme with two circuit breakers and two protection devices**

Modern zone-selective interlocking allows improvements in clearing time, provides interlocking of LV-to-MV devices across transformers, can be applied with directional relaying, and can provide other advanced capabilities. Proper implementation of modern interlocking schemes can improve protection speed and sensitivity for buses located in upper tiers within any distribution topology. In rare cases, selectivity may be slightly improved using ZSI capabilities.[12] For additional reading on advancements in zone-selective-interlocking, see Valdes et al. [B41] and [B42].

## 8.2 Coordination studies and delay settings in ZSI schemes

Zone interlocking of LV circuit breakers is widely available for use with short-time and ground-fault functions. In some situations, circuit breakers might be able to implement instantaneous protection within a ZSI scheme, at least at the bottom tier, and in some cases at upper tiers as well. The adjustability of short-time and ground-fault zone interlocking can also vary by manufacturer and product. Most manufacturers allow the user to adjust the backup protection delay, or "restrain setting" applied on the upper-tier circuit breaker(s). The circuit breaker with primary clearing responsibility (i.e., the circuit breaker for which the fault is within the primary zone of protection) will clear the fault in accord with its "unrestrained setting" delay, which might or might not be adjustable by the user. Typically, adjustable unrestrained settings provide the user greater flexibility to coordinate selectively the circuit breakers in the lower tiers of a ZSI scheme with overcurrent devices and loads farther load-side that are not part of the ZSI system. There might be breakers with instantaneous clearing times that are not necessarily coordinated with the minimum delay available, or there might be a need to allow expected transient currents (e.g., transformer and motor inrush currents). However, circuit breakers located above the tier of breakers closest to the load can generally have unrestrained settings at minimum delays because the zone interlocking with the load-side feeder will coordinate the upper tier breaker with the load-side breakers not in the ZSI system. In these circumstances, it is possible for bus protection to be

[12]Traditionally, ZSI is not considered capable to provide selectivity improvements, only protection improvements.

faster than the feeder-cable protection. This type of function should be confirmed with the manufacturer of the protective devices used. In component relays this will require separate inverse functions for blocking logic and protection and ability to implement the required logic. In LV trips the capability should be discussed with the manufacturer.

### 8.3 In-zone, unrestrained-protection and restrained backup-protection

When conducting a coordination study and an arc-flash study it is important to understand the difference between in-zone unrestrained protection, and restrained backup-protection—it is important to ensure that the system is properly adjusted for both. Traditionally, coordination studies do not represent the unrestrained protection provided by ZSI schemes very well. The coordination model typically shows nested restrained time current curves that represent the backup protection timing and sensitivity provided by devices other than the bottom tier circuit breakers in the system. For upper tier devices, the protection represented (restrained) is only active if a lower tier device fails to operate and does not clear its fault current properly. The actual close-in (in-zone) unrestrained protection provided by the upper-tier circuit breakers, which often is the bus protection, is not graphically represented in the traditionally modeled coordination-study time-current curves. The predominant issue is how this modeling affects evaluation of arc-flash energy; however, modern coordination software might implement capability for dynamic fault scenarios that will shift curves as appropriate based on modeled fault location.

Not all manufacturers or devices implement delay settings the same way. In LV ZSI implementations within LV circuit breaker trip units, unrestrained and restrained protection might be selected various ways:

a) User selects “restrained” backup timing and the trip unit automatically sets “unrestrained” protective timing. This is the most common and simplest configuration in LV trip units.

b) User selects both unrestrained and restrained timing. This configuration is more complex but might provide greater flexibility. It is important to properly identify which delay is the restrained and which delay is the unrestrained when adjusting the settings in the trip unit.

c) User selects the same unrestrained protective timing for all tiers and a fixed “delta” time delay to be added to upper tier devices based on load-side fault location. This configuration might allow for tighter backup timing but requires some sort of centralized control to identify fault location and logic that includes system topology considerations. This scheme might be able to adapt backup delays to topology changes as well. See Valdes et al. [B42] and [B43] for further reading on this ZSI scheme.

d) User sets protection threshold and trip unit has only fixed timing for in-zone protection and a second fixed timing for out-of-zone backup timing. This scheme is suitable for high fault ranges where excessive backup timing might be undesirable and in-zone protection is desired to occur as quickly as possible.

e) User sets two or more alternate setting groups composed of multiple settings and the restraint signal is used to alternate between them. This method is more common in MV protection but is also available in LV trip units. It requires multiple user settings but provides very flexible alternate protection that can be used as backup protection. The signal required to alternate between setting groups is more appropriately called a logical input than a restraint signal as it can be used to alternate between protective settings used to back up a lower-tier failed circuit breaker or to reset bus protection as required for varying system topologies.

When the available short time or ground-fault delay settings permit three or more circuit breakers to be coordinated, the restrained timing on a trip unit could be selected in a manner where all the upper layers of trip units are selectively coordinated one to the other in the traditional method where ZSI is not being used. The case of main-tie-main systems is one where this might occur most often. However, these nested delays are not strictly necessary. Backup, restrained timing could be set the same for all protective tiers. If the in-zone protective timing and the backup timing coordinate, and all circuit breakers operate properly, the system

should be selective under all fault conditions, regardless of whether backup timing is nested in multiple levels or not. However, if a lower tier device fails to clear properly and all backup timing is set the same for multiple tiers, then multiple tiers of line-side devices might trip together. This may, or may not, be desirable when one considers that this only happens if a fault has happened downstream and the circuit breaker that is intended to operate fails to clear the fault. Tripping multiple devices may be desirable to minimize equipment damage and ensure reliable fault clearing given evidence of a compromised protective scheme. See Figure 12 for an illustration of this concept.

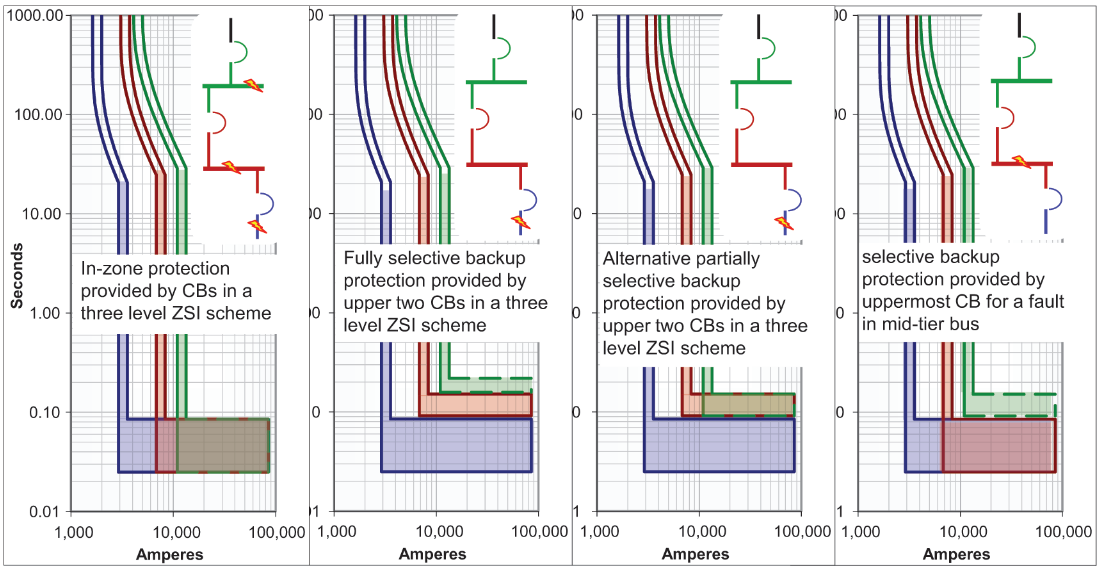
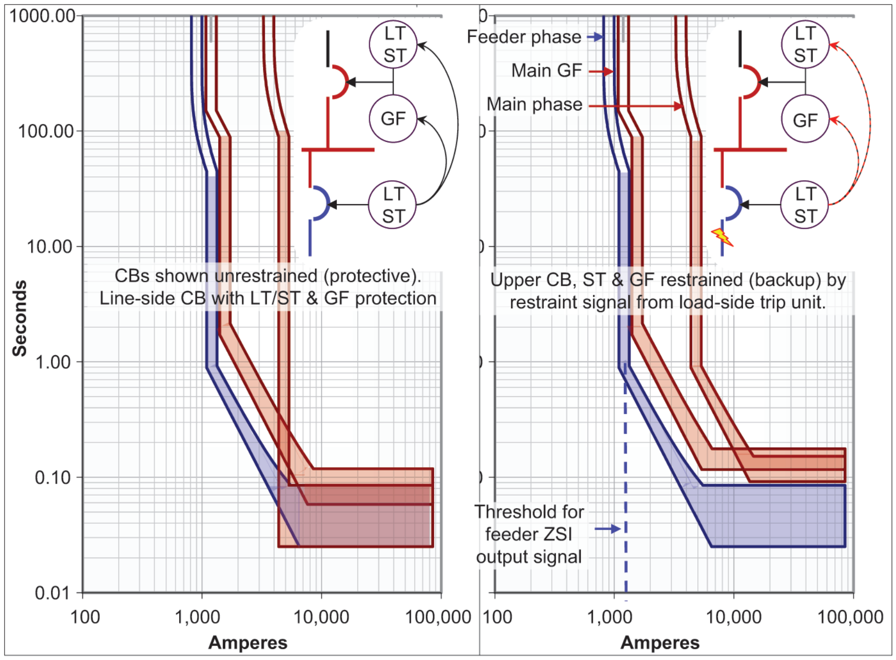



**Figure 12—Backup settings alternatives in a zone-selective interlocking scheme**

## 8.4 ZSI schemes and protection algorithms

ZSI or blocking schemes are applied to control various protective functions. The most commonly available schemes in LV trip units apply to short time and ground-fault protection.

It is important to note that the ZSI schemes implemented in trip units or protective relays might allow the manipulation of multiple protective functions (e.g., short-time, ground-fault, instantaneous) upon receipt of a blocking signal. Typically, only one signal path is used, and if the receiving unit does not know why the signal was sent; it will shift whichever functions are ZSI-enabled to their restrained settings. This allows a lower tier device to have only short-time zone interlocking implemented, but the device on the line side might have ground-fault and short-time protection shifted if the phase overcurrent of the lower tier device can be adjusted to coordinate with the line-side ground-fault characteristic. The signal from the lower tier will shift both upper protective functions once the load-side short time ZSI function picks up, which might occur immediately after current exceeds the pickup threshold setting. Figure 13 illustrates an example.




LT = Long Time, ST = Short Time, GF = Ground Fault

**Figure 13—Time current curves showing feeder CB with only short-time interlocked with a CB equipped with both short-time and ground-fault protection**

Advanced algorithms and circuit breaker protection systems can implement enhanced zone-selective-interlocking not previously available. Directional zone-selective-interlocking allows interlocking to operate in systems with multiple sources and ties restraining the proper source side circuit breaker depending on fault location. Directional capability can also help ensure that a protective device does not issue a restraint signal because of regenerative fault current supplied by a motor onto a bus fault upstream. Other algorithms allow separate interlocking of instantaneous and short-time protection or may be capable of automatically shifting the current pickup thresholds which allows pickup settings to be set to the same current threshold without regard to maintaining separation between pickups due to tolerance considerations.

## 8.5 ZSI signal timing and creation of custom blocking schemes

The underlying principle in a ZSI scheme between two or more tiers of protective devices is that when two devices in series sense the same fault current, the load-side device sends a signal to the line-side device indicating that it has sensed the fault and is in the process of reacting to it. The line-side device processes this signal as a restraint upon its protection algorithms and delays them from a faster more protective operating mode to a slower backup mode that allows enough time for the load-side device to clear the fault. The operational requirement is that the line-side device receive and process the restraint signal prior to itself asserting a trip and being committed to operating at its faster protective timing. See Valdes et al., Section V B, page 1642 [B41].

Figure 14 illustrates the timing of a ZSI interlocking signal issued by an LV circuit breaker and the timing requirements for an instantaneous protection function of an MV instantaneous (device 50) relay. The left diagram shows an LV circuit breaker short-time and instantaneous curve along with the associated restraint signal timing issued by the same circuit breaker trip unit. The center panel shows the timing of the various subsystem functions associated with the instantaneous function of a protective relay able to receive a logical input and process it to alter its protective functions. The lines in the center panel, from bottom (fastest) to top (slowest) represent the following:

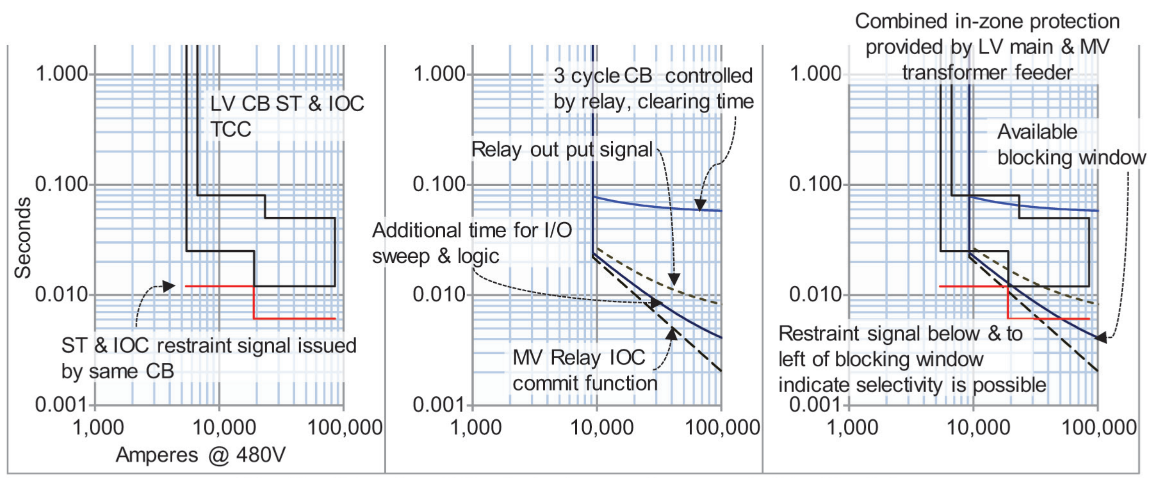
— Commit time for the relay, i.e., the time it takes for the relay algorithm or circuitry to make the irrevocable decision to assert a trip. In this case, the minimum time that decision can take. For instantaneous elements, the commit time is often inversely proportional to the ratio of fault current to threshold pickup setting;

— The second line above that represents the additional time the relay allocates to sweeping its logical inputs and processing associated logic. At the end of this time, the relay will assert its trip if the logic allows it. This line may be viewed as the "blocking window." If the blocking signal arrives before this time, the relay logic can block or alter its operation and not assert a trip even if the fault current had previously exceeded the commit time;

— The third line represents the output contact from the relay. Output contacts might be solid state or mechanical. Mechanical contacts usually are a few milliseconds slower than solid state contacts;

— The fourth, top most line represents the clearing time of a 3-cycle MV circuit breaker.

The third panel superimposes the LV circuit-breaker, short-time and instantaneous curve, its associated issued restraint signal, and the various lines representing the MV instantaneous element and MV circuit breaker. The LV restraint signal is to the left and below the MV line representing the MV instantaneous trip blocking window that indicates these two devices might be made selective by using the LV restraint signal to alter the MV relay operating characteristics. Many modern digital relays offer the ability to block instantaneous protection. Operational details may vary by manufacturer and device model and should be obtained from manufacturers' application literature or by consultation with the manufacturer for a specific relay and trip unit. This capability is particularly useful for fast protection of the transformer secondary bus between the transformer secondary terminals and the first LV device.




CB = Circuit Breaker, IOC = Instantaneous Overcurrent, ST = Short Time,
Commit-time (minimum) taken by algorithm or circuity to irrevocably decide to assert a trip

**Figure 14—Interlock signal timing for circuit-breaker trip units and protective relays**

## 8.6 Circuit breaker failure schemes as backup bus protection

Circuit breaker failure (CBF) schemes are usually used only in complex topology schemes that have multiple sources and buses interconnected. However, CBF schemes operate in a similar manner to ZSI schemes, but timing is initiated within breaker-failure logic in the CB that should be protecting the faulted zone, starting upon assertion ($t_0$) of the lower-tier trip command, rather than when fault initiation was determined. Backup protection is provided by transfer tripping from the lower-tier device to the upper-tier device(s) feeding the circuit if the logic determines that the primary protective device has not interrupted the fault current as expected.

CBF schemes provide supplemental backup protection for through faults and are not primary protection to upper-tier buses. Figure 15 shows a schematic comparison of a CBF scheme versus a ZSI scheme. For further information on CBF applications, see IEEE Std C37.119 [B20].

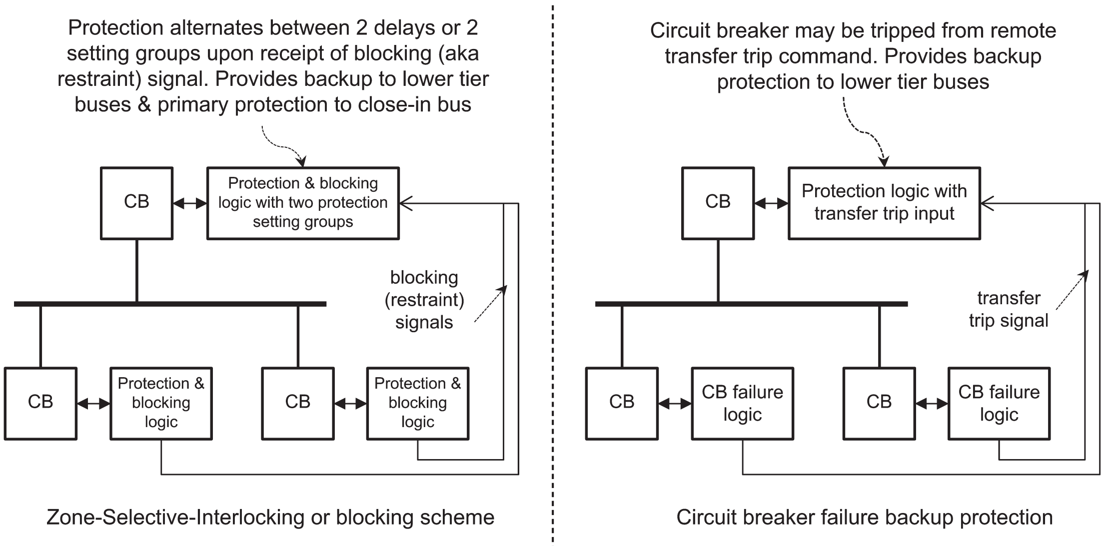



**Figure 15—Comparison of zone-selective-interlocking logic to a circuit breaker failure logic scheme**

A word of caution is appropriate for CBF schemes. Added complexity in a protection system provides added opportunity for equipment failures, wiring failures, and testing failures. CBF protection should not be considered for simple systems in which the only outcome of the circuit breaker failing to trip is that the line-side circuit breaker or fuse clears the fault. Normal backup protection, potentially enhanced with ZSI, is usually good enough for radial distribution topologies. CBF schemes are for buses with multiple sources of power where the failure of a circuit breaker to properly isolate the fault may cause multiple systems to be impacted. This type of protection is usually only seen in utility applications for major substations, but with distributed resources becoming much more common, it is becoming more common for complex industrial and commercial power systems.

# 9. Differential protection

## 9.1 Bus differential basics

Bus-differential relaying can provide sensitive, high-speed, selective protection for buses, including switchgear buses. A bus-differential relay measures all currents entering and exiting the protection zone and operates if the difference between the current sources and current loads is above the differential protection threshold. Because of this inherent selectivity, a differential relay does not need to have intentional delays to coordinate with relays in adjacent zones, and it does not need to coordinate pickup thresholds with other protection—a benefit especially when large fault currents flow through the differential zone. Bus-differential protection is used when high-speed fault clearance is required to limit the damaging effect to equipment and to maintain service to as much load as possible. In addition, it permits complete zone protection coverage and overlapping with other power-system relaying as indicated in Figure 11, Figure 12, and Figure 13, for a variety of bus configurations. One of the challenges associated with the applications of bus differential relays, is the behavior of the current transformers associated with the differential schemes. Current transformers saturate when subjected to excessive fault currents and to dc components in currents under transient fault conditions at fault inception (IEEE Std C37.110). Saturation of one or more of those current transformers providing

inputs to the differential scheme may cause relay mis-operation and compromise the scheme reliability. CT requirements for differential schemes are discussed in detail in IEEE Std C37.234, IEEE Std 3004.1, and other literature. It is advisable to review such references as well as the relay supplier requirements prior to the selection of the connected CTs. CT characteristics are especially important when using high impedance bus differential relays. Modern low impedance bus differential relays are developed with separate input modules for each CT input signal, and each input is digitized before current inputs are vectorially summed in the relay. Some details are discussed in the subsequent clauses and more details can be found in associated literature.

Bus-differential relaying often is applied to complex systems that have multiple sources and perhaps multiple buses at the same voltage level. Improved arc-flash protection is another reason to implement differential protection, to provide the fastest and most sensitive protection without sacrificing system reliability. Traditionally, these goals have been used to justify the extra cost and complexity of high-speed bus-differential relaying. Advances in modern digital relays, digital communications, and alternate sensing techniques has lowered the cost and complexity of implementing differential protection in industrial and commercial applications and make applications in commercial LV systems more feasible.

The basic principle of differential protection is that, under normal conditions, the phasor sum of all measured currents entering and leaving the bus is zero (Kirchoff's current law). This is ideally always true under normal load conditions, otherwise, a fault has occurred within the protected zone.

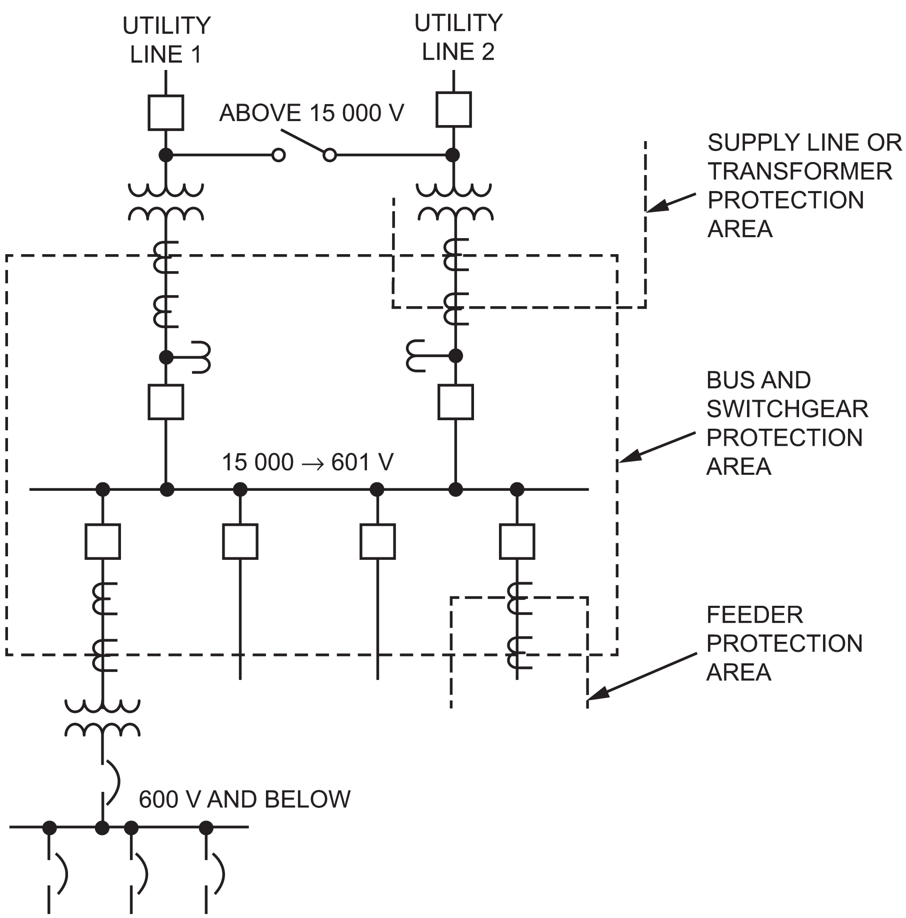



**Figure 16—Single-bus scheme with bus-differential protection and other overlapping protection zones**

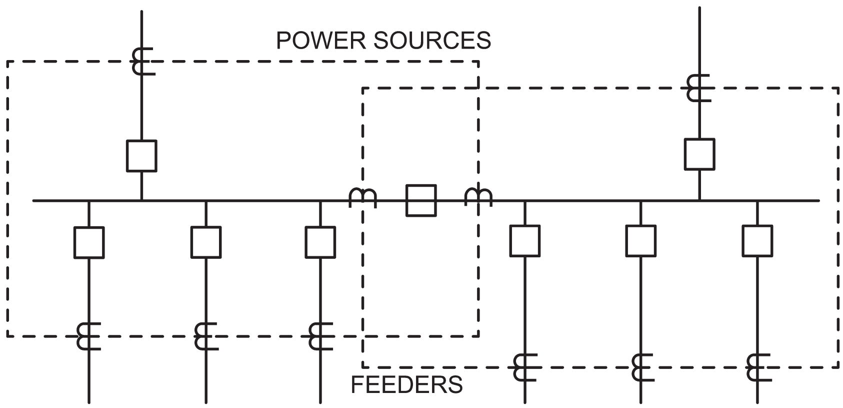



**Figure 17—Sectionalized-bus scheme with bus-differential relaying, overlapping tie-circuit-breaker protection**

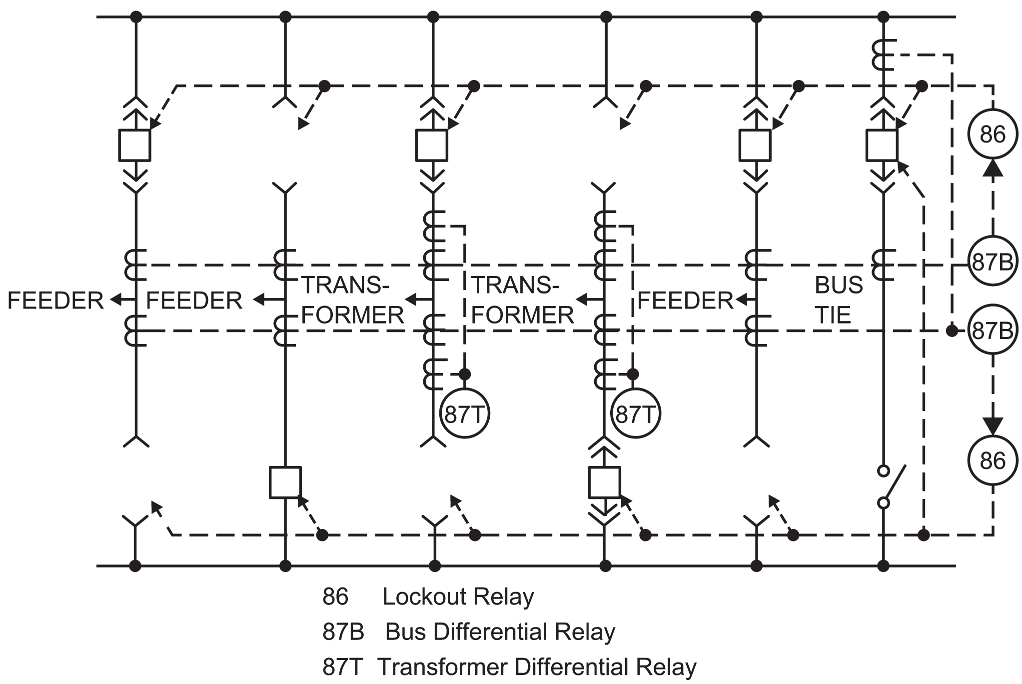



**Figure 18—Double-bus scheme with bus-differential relaying and other overlapping protection zones**

Differential relaying is typically provided to supplement basic overcurrent protection. It is frequently used on a 15 kV-bus, sometimes on a 5kV-bus, and with increasing frequency, on LV buses. The following factors are often used to determine whether differential relaying should be provided (see Cable et al. [B5]):

— Degree of exposure to faults. For example, open outdoor buses have a higher degree of exposure; and metalclad switchgear, properly installed and in a clean environment, might have minimum exposure. Contaminated environments increase the possibilities of faults, and equipment located in these environments needs better protection;

- Magnitude of the fault current causing damage of the bus components and voltage depression impact to the adjacent electrical equipment as a result of slow fault clearance, such as motor control circuit drop-out or synchronous motors falling out of synchronism;
- Power-system stability. The capability of a system to return to a stable, steady-state mode of operation after a system disturbance might require high-speed bus differential relaying. The faster clearing time obtained with high-speed differential relaying enhances the probability of maintaining stability through and after a fault;
- Use of sectionalized-bus arrangements that require the use of other, more complex protection methods. Sectionalized-bus arrangements make differential protection more useful and desirable, particularly when secondary selective distribution systems are used. The faulted bus can be isolated quickly and continuity of service maintained to a portion of the load served by any other bus;
- Effects of bus failure on other parts of the power system and associated processes. On a major plant bus, the cost of differential relaying is usually insignificant when compared with the savings associated with the reduction in damage to the equipment and the reduced outage time of important plant or process facilities. This cost can include the cost to repair electrical equipment, clean up production machinery and processes, as well as the opportunity cost incurred and lost revenue resulting from the inability to continue plant operations.
- If problems exist in selectively coordinating the system overcurrent-relay settings or the selective coordination requires excessive delays, differential relaying is effective in obtaining selectivity and faster protection simultaneously. An example is a system that consists of major bus distribution lineups at the same voltage level, with one bus feeding another. This configuration generally results in unacceptably high overcurrent relay pickup and delay settings required to obtain coordination.
- Arc-flash incident energy protection. Delays and nested pickups, often required to provide selectivity for bus main breakers, can increase arc-flash incident energy. The energy released by an arc flash can create significant hazard to operating and maintenance personnel. Sensitive bus-differential protection should reduce the severity of the hazard while enabling selectivity for through-faults at protected buses. Where improved arc-flash mitigation is desired, bus-differential protection is an alternative to losing selectivity to overlapping short-time bands and instantaneous protection or slowed protection required to maintain selectivity.

On a bus fed by a local generator, bus differential relaying is recommended to clear the bus quickly and minimize impact on the generator system. Simple overcurrent relays might not be sufficiently fast or sensitive to protect the generator if these are set to be selective with other load-side protection.

The differential protection methods generally used are the following:

- High-impedance differential relaying
- Percentage-restrained differential relaying
- Differentially connected overcurrent (instantaneous or delayed)
- Partial differential (sometimes not considered a differential scheme and called “current summation”)

The differential relay should trip all circuit breakers connected to the bus. Typically, a high-speed, multi-contact lockout relay (device 86B) is used for this purpose. This auxiliary device should also have normally closed contacts in the circuit breaker closing circuits to prevent inadvertent manual closing of a circuit breaker on the fault until after the incident has been investigated further. The lockout relay then must be reset manually before any circuit breakers can be closed. In some schemes, where optimum protection speed is desired, controls might be connected such that source circuit breakers are directly tripped by the protection relay and the lockout relay is used to trip feeders. Modern digital differential relays may have enough contacts to trip all bus breakers and provide lockout functionality.

Figure 19 shows a simple, current-based differential scheme that may be created by simply connecting current sensors in a differential manner from each source and feeder circuit in parallel to a simple overcurrent relay using the net difference from the sum of all currents as the input to the relay. If the current into the bus through the source is equal to the current leaving the bus through the three feeders, the net sum is zero and no current flows through the relay. When a fault occurs on the bus, the source contribution into that bus does not flow through the feeders and hence is sensed as a differential current by the relay. This simple scheme requires that the characteristics of the CT be considered. CT ratios should match, however other characteristics may vary. Reviewing CT characteristics with the relay manufacturer is recommended. Generally, this simple scheme will require the protection to be set high (50 device) or delayed (51 device) to prevent CT performance from negatively impacting security.

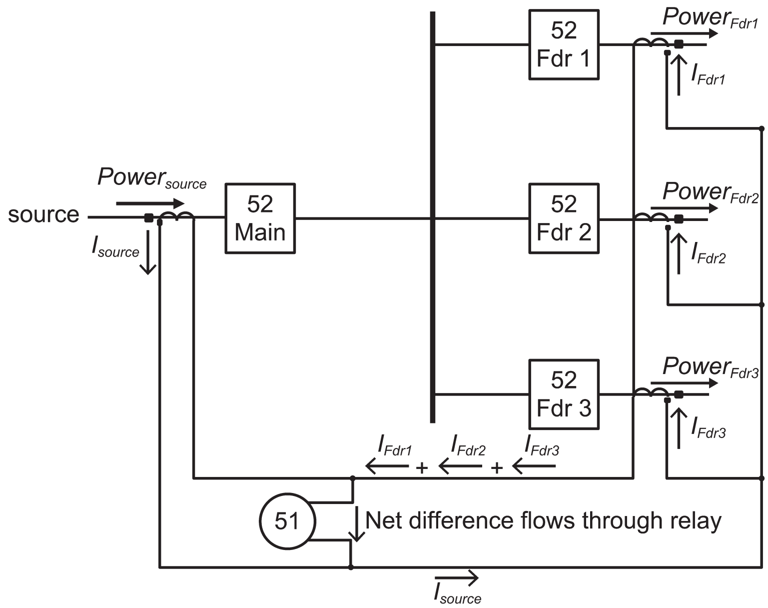



**Figure 19—Simple current-differential scheme using overcurrent relay**

The simple differential scheme such as shown in Figure 19 might be susceptible to false operation because of sensing inaccuracy during large through faults. A load-side fault could cause enough current to flow that the source and feeders CTs, even if nominally identical, could produce enough difference in secondary current that the relay could incorrectly assert a fault that is not there. Adding delays or increasing the operational threshold are ways to minimize the possibility of incorrect operation; however, slowing and desensitizing differential protection is not usually desirable, and to some degree, defeats the purpose of having differential protection. This type of implementation might be suitable for small systems with a very limited number of circuits. The more common types of differential relays employed in industry today are called low-impedance and high-impedance differential relays. Both types of relay expand the number of circuits that can be accommodated and implement techniques to allow sensitive thresholds and very fast operation that can perform as well as fast instantaneous protective elements in single-circuit protective relays. In the past, high-impedance differential relaying was generally considered superior; however, with improvements in digital relays, low-impedance differential relaying can perform as well as high-impedance differential relaying in speed and sensitivity while providing for a more flexible implementation.

## 9.2 High-impedance bus-differential relays

### 9.2.1 General

In classic high-impedance bus-differential relays, CT secondary currents are summed via their secondary circuit wiring as shown in the upper portion of Figure 20. The net differential current is forced to flow through a resistance as shown in the lower portion of Figure 20. The scheme is relatively simple and straight forward. Accordingly, it remains widely used despite the need to address certain practical considerations as discussed further throughout this subclause.

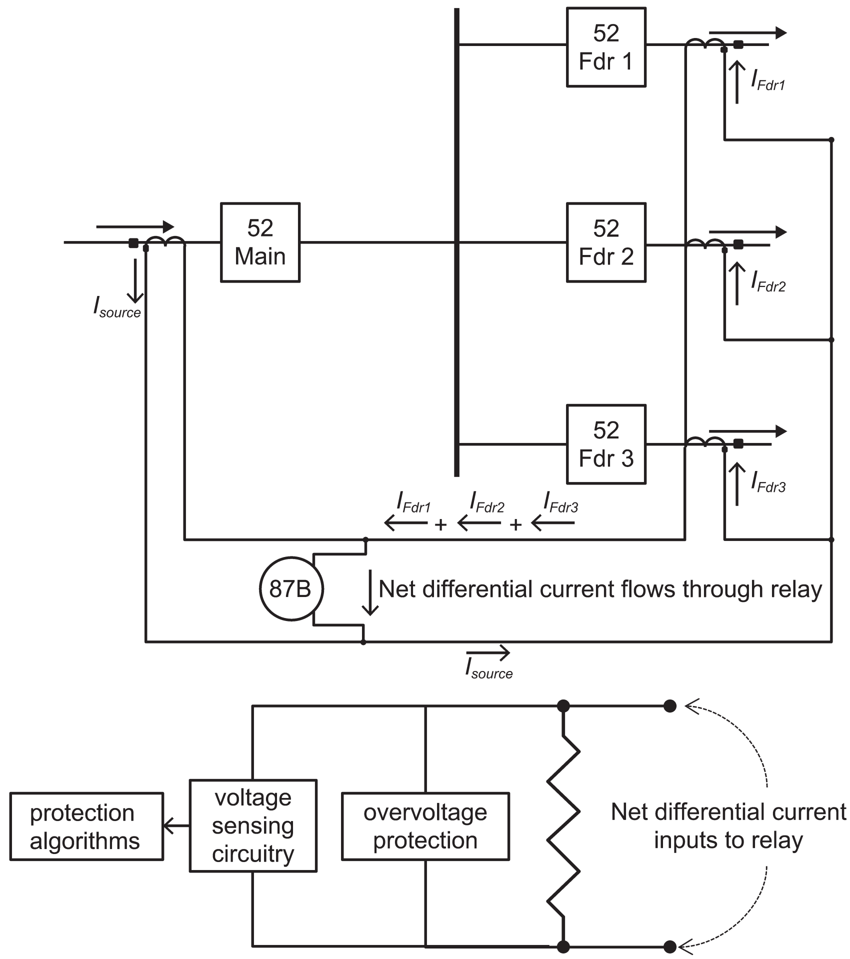



**Figure 20—High-impedance bus-differential scheme (high impedance bus differential relays sometimes designated as 87Z or 87BZ instead of 87B)**

The CTs used with traditional high impedance differential relays must have the same ratio, enough accuracy, matched characteristics if possible, and proper polarity connection to ensure that the secondary current outputs from the paralleled CTs have a vector sum of zero in the same way that the primary currents in the bus sum to zero during normal load conditions. Current differences are forced through the high-impedance input at the bus differential relay causing a voltage across the relay. In some cases, the relay is in series with a resistor, and those relays will operate from the current through the relay and resistor. The relay is set to trip based on the voltage across the relay and can be sensitive to small differential currents. Typical relay settings allow one CT to saturate without relay misoperation. During external faults, with saturation of some of the CTs, the voltage does not rise above a certain level defined by the saturated CT impedance and wiring impedance.

The circuit is required to have overvoltage protection, typically in the form of a metal oxide varistor, to limit the voltage across the relay-input resistor created during internal faults. This type of relay has been used for several decades because it is robust, cost effective, secure, and fast. Limitations of high-impedance differential relays and precautions while applying them can be summarized as:

- Dedicated, well-matching CTs are required. The CTs should have distributed secondary windings that have little or no secondary leakage reactance. Manufacturers of the relays provide guidance on CT selection to ensure that the CTs are properly matched to each other and to the relay capability;
- CTs must be sized to have an accuracy class that will produce an operate signal on the relay while saturated;
- CT secondary circuits must be connected with the correct polarity so secondary currents flow in the proper direction.

Under normal load conditions, differential current should be zero through the differential impedance. Under through-fault conditions, although bus currents are still balanced, one or more of the CTs might saturate. A fully saturated CT produces reduced secondary current and can become a (relatively) low-impedance path for other current sources in the circuit. Secondary CT wiring is an important consideration in determining the voltage across a saturated CT. It is usually preferred to run CT secondary leads to minimize wiring impedance and equalize resistance among the various load circuits. The operating-threshold voltage for the differential protection must be greater than the voltage that could occur across the parallel path provided by a completely saturated CT. For a bus fault within the differential zone, a large voltage should be produced across the relay impedance. The overvoltage protection provided by a metal-oxide varistor clamps the voltage peaks to a level acceptable for the relay. The relay operational threshold must be set below the clamping voltage created by the overvoltage protection. Manufacturer’s literature should be consulted to secure relay behavior under system conditions especially:

- Through faults that saturate one or more of the CTs;
- Internal faults that saturate the CTs;
- Internal faults that could result in a very large differential current and consequently cause large voltages across the relay sensing impedance;
- Internal faults that are not cleared sufficiently can quickly drive current through the relay impedance longer than the relay is able to withstand.

See Behrendt et al. for further reading on high-impedance relays [B4].

### 9.2.2 Through-fault operation

Under severe through-fault conditions, CTs carrying the most fault current might saturate. The relay tripping-voltage threshold must be set above the voltage that could develop across the relay with a completely saturated CT. A completely saturated CT produces no current output and becomes simply a (mostly resistive) impedance in the circuit. The CT wiring and internal resistance are small relative to the internal resistance of the high-impedance relay path. Therefore, the worst-case voltage across the relay under a large through-fault condition is the voltage drop across the combination of saturated CT wiring and saturated CT internal resistance. The voltage selected as a tripping threshold must be greater than the possible voltage that could develop across a saturated CT and associated wiring.

The relay setting threshold should have enough margin to account for potential variation in the available fault current and in the impedance used in the calculations. This threshold affects the minimum sensitivity setting for the relay. To simplify calculations, it is recommended that all CTs be connected to one junction point or terminal board. CTs should not be connected into subsets and the subsets brought to a common connection point separately.

### 9.2.3 Internal faults

During a high-current internal-bus fault, the relay presents high impedance to the flow of CT secondary current. This impedance causes a large voltage to be developed across the relay. Even if the CTs on incoming circuits eventually saturate, a large voltage is developed during the first part of the half cycle prior to CT saturation. Relays should be set to operate from that voltage during the time prior to CT saturation. This setting should provide the relay enough information and time to make reliable tripping decisions. Manufacturers implement various filtering, sampling, and signal processing techniques to improve sensitivity, accuracy, speed, and reliability for the sensing circuit—even when fault magnitudes might be large and source CTs reach saturation. The net current flowing through the sensing circuit can be very non-sinusoidal; however, modern relays can discern a fault within a cycle of fault inception.

The voltage peaks created during a fault can exceed the voltage withstand of the relay and even prove hazardous, hence the voltage must be clamped to a reasonable level that is greater than the expected pickup threshold of the relay.

### 9.2.4 Protecting the high-impedance differential relay from excessive current and circuit-breaker failure

The relay current-withstand and overvoltage protection energy limits might be exceeded in cases where the circuit breaker that the relay controls does not open quickly enough. Additional protective elements need to be included for such situations. Common implementations include a parallel metal oxide varistor (MOV), or shunting the differential current through a parallel, low-impedance circuit made of internal relay contacts or using an external 86 auxiliary relay connected in parallel with the protection relay's sensing circuit.

### 9.2.5 Additional relay functionality

High-impedance differential relays may implement a series overcurrent function (50/51) that provides back-up protection and continues to operate even after the shunt bypass contact is closed to protect the main sensing circuit and overvoltage protection.

A high-impedance differential relay cannot implement functions that require measuring any single circuit current because the current information at the relay always represents the net total current flowing in the zone.

One last concern is that, because the high-impedance relay can be set very sensitively, it is important to account for normal and acceptable currents that may exist or temporarily occur within the protected zone. These currents may result from auxiliary control power transformers and even currents shunted to ground by arresters or surge protective devices.

## 9.3 Low-impedance bus-differential relays

Modern, digital, low-impedance differential relays have fewer restrictions than older electromechanical versions in the way these relays are wired and in CT selection. Figure 21 shows a simplified, low-impedance differential relay connection. Generally, these differential relays share the following characteristics:

- CTs may be shared with other metering and protective functions within the relay;
- CT ratio can be corrected or changed at the relay as required;
- The relay will impose a threshold-restraint function to desensitize the relay in proportion to some measure of the through current in the differential zone to guard against false tripping from CT sensing error, see Thompson [B34];
- The relay can adjust for a CT wired with any polarity; however, it is recommended that all CTs be wired with a consistent secondary current direction to facilitate trouble shooting.

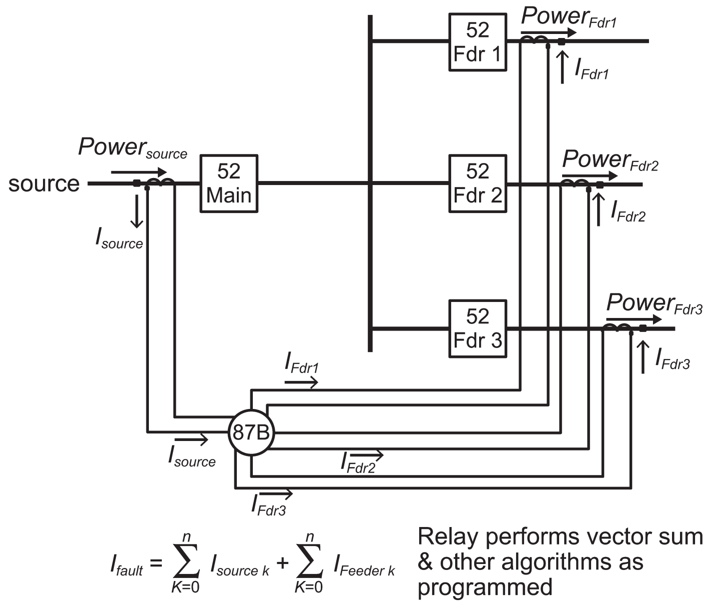



**Figure 21—Simplified, low-impedance relay scheme**

Modern low-impedance differential relays might implement various algorithms creating a restraint function and use separate measured currents (or rate of change of current) to improve protection sensitivity, speed, and prevent false operation. Because the relay receives each CT signal independently, the relay can implement various additional protective and measurement algorithms with each separate CT signal and any combination of CT signals. Additional protective functions such as breaker-failure detection, overcurrent protection of load-side circuits, and other multi-function protection, with sophisticated algorithms may be provided by the same relay.

A commonly used method to account for measurement error in low-impedance differential relays is the percent-restraint function. The relay sums the currents (vector sum of phasors) from all CT inputs to detect the differential-current increase resulting from an internal fault. To account for errors introduced by variations in CT performance and by CT saturation, the relay also may implement one of various methods based on the measured current magnitudes to create a restraint current. The differential current from the phasor summation, referred to as the operate current, is compared with the restraint current. The relay operates when the operate current exceeds a minimum threshold and a percentage of restraint current. Graphically this is shown as a slope called the percentage-current-differential characteristic for the differential relay. Figure 22 illustrates this principle. Low-impedance differential relays that implement this characteristic are referred to as percentage-differential relays. A second, steeper slope is often added to address the increasing inability for the CTs to accurately replicate higher primary currents and hence ensure that the relay does not misoperate if a CT is saturated during a high-current fault. This second slope makes the relay stable against misoperations but can significantly desensitize the protection during a high-current fault. The second slope is also shown in Figure 22.

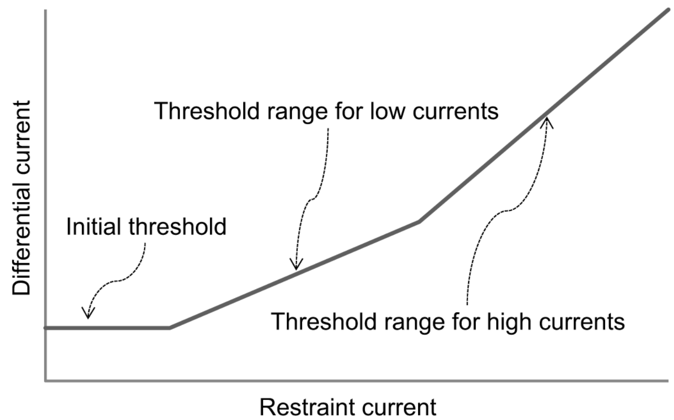



**Figure 22—Percentage-current-differential characteristic**

Modern, digital, low-impedance differential relays implement additional algorithms to detect saturated CTs and the pending saturation of a CT. These algorithms vary by manufacturer. These algorithms improve the sensitivity and security of modern, digital, low-impedance differential relays.

The relay must have separate input connections for each CT that is part of the differential scheme. Typically, that will be three CTs per source or feeder circuit, one for each phase conductor. One technique to connect more circuits to any one relay is to put CTs for multiple circuits in parallel and use the net sum of these CTs as an input to the relay. This technique requires that the paralleled CTs be of equal ratio and class, and that the combined expected secondary current from the paralleled CTs does not exceed the relay input signal ratings. The manufacturer's literature should be consulted when this technique is used to determine if this might cause issues with protection algorithms. When implementing low-impedance differential relaying, consideration should be given to any additional circuits that might be added in the future to ensure that the relay has sufficient inputs for planned expansion of the bus system. See Kasztenny [B22] and Thompson [B34] for additional reading on percentage differential relays and Holback [B9] for a comparison between high-impedance and percentage differential relays.

## 9.4 Modern differential-protection alternatives

Using distributed processing of power-system information, the equivalent of low-impedance differential relaying can be implemented in an alternative manner. Systems might use iron-core sensors or air-core sensors (a.k.a. Rogowski coils) and digitally process the information locally, with a process bus merging unit assigned to a circuit breaker cubicle. The accumulated data are sent to a central computer processing unit (CCPU) using modern digital communication methods. The data from various circuits can be analyzed at the CCPU as appropriate for the system topology. The information sent from each circuit must include the fundamental current-phasor data and must be time stamped or otherwise tightly synchronized with each other at the CCPU. Data provided at the CCPU might include non-linear and non-fundamental current components and voltage information. Like a traditional low-impedance differential relay, the CCPU has all the data required to protect separate circuits in addition to providing differential protection. Additionally, it can implement various methods to ensure fast, accurate, and reliable detection of an in-zone fault. This arrangement can provide additional protection and control capabilities. Phasor currents can be vector summed at the CCPU to produce a differential current as in a directly coupled, low-impedance differential relay, and the various phasors can be compared to identify the direction of current flow, and consequently the location of the fault. When directional comparisons are made, exact measurement of the fault current is less important, if it is known that it is greater than the set protection threshold. See Valdes et al. [B42] and [B44] for additional reading on this type of system.

An additional benefit of using digital communications to provide current data from the circuit-breaker cubicle to the CCPU is that CT leads are always connected to the local node at the circuit breaker bay. For this local connection, the CT leads do not extend to a central differential relay location. Thus, CT burden is reduced and the CT is less likely to saturate, and CT wiring does not have to cross where equipment is separated for shipping purposes (shipping splits).

Distributed data acquisition combined with centralized data processing provides an economic and flexible solution. This solution accounts for CT saturation, uses the same sensors for multiple functions such as metering, control and other protection, and uses integral sensors that are normally provided in LV circuit breakers and in some MV circuit breakers, as well. These systems make differential protection a reasonable option in some LV systems where traditional differential protection and its components might otherwise be considered too costly, too complex, or incapable of fitting into the available space. Distributed systems can easily account for dynamic changes in system topology and circuit-breaker status and can define a zone of protection as required in response to different system conditions.

Schemes using communications technology can provide differential protection over large systems where traditional CT wiring would be impractical. IEC 61850 communication may also be used to implement directional comparisons. These might be less demanding of communication buses because less information is communicated from the local data-acquisition node to the central-processing node at which the comparisons are made. See Apostolov et al. [B2] and [B44] for additional reading on this subject.

A communications-based architecture is shown in Figure 23. Alternative architectures are possible with different levels of functionality distributed between the local and centralized communicating devices. Information distributed within the system can include several discrete signals such as circuit-breaker status and blocking signals as well as analog current and voltage phasor, sampling data.

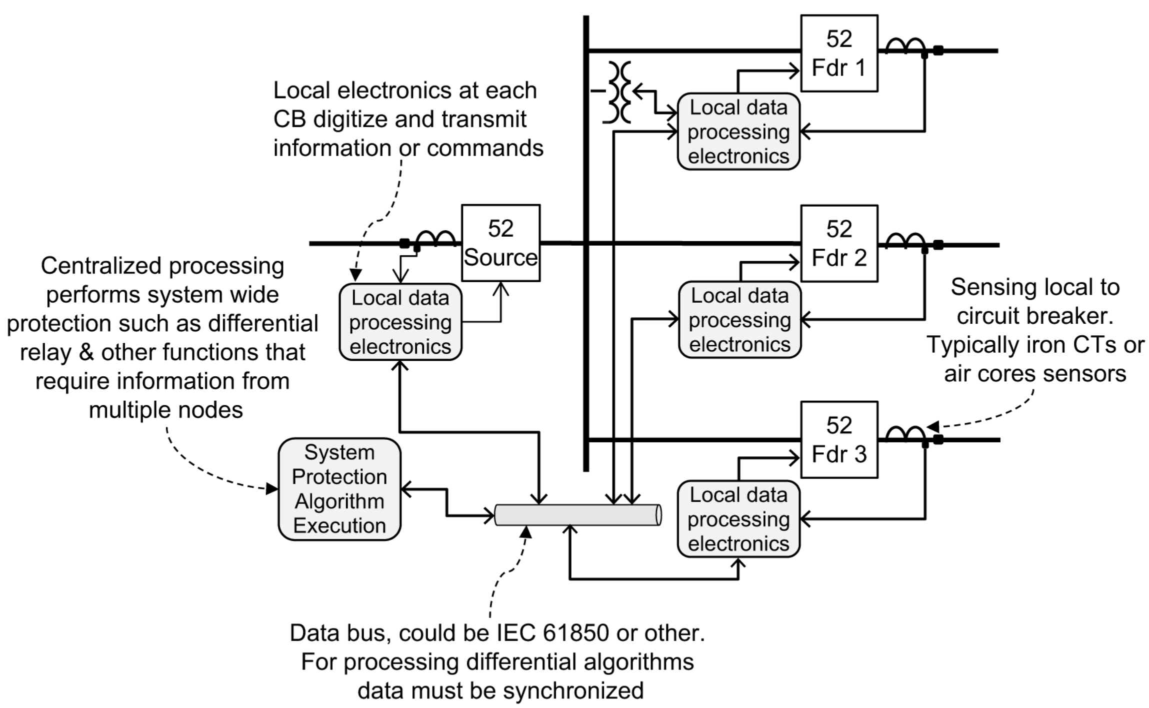



**Figure 23—Differential scheme implemented in system with digitally communicating devices**

Among the drawbacks of this type of scheme is the wide variation that might be found between alternatives available and the unfamiliarity of users with this type of protection. In a centralized scheme, the provision of multiple important protection and control functions in one processor raises the concern that there might be a single point of failure affecting too many important functions. That concern can be alleviated by providing redundancy in sensitive portions of the system and by designing the system such that, in the event of a single device or communication failure, sufficient protection and control remains to keep the system safe and operable.

When implementing protection and control schemes using centralized processors, there are many factors that need to be considered to ensure that protection is fast and reliable, including being able to accurately predict protection timing regardless of other demands for available communication bandwidth, processing power, or available memory. Generally, monitoring functions will be lower priority than control functions, and control functions will be lower priority than protection functions. Fault events may cause significant increases in data to flow, and this can cause the system to operate in an unintended way if the design does not properly account for the potential large flow of time-critical data during fault events. Designing complex control and monitoring systems is complex and requires skilled personnel. Adding protection functions makes it even more critical that system designers understand the ramification of all system design decisions and that the system be robustly tested prior to full implementation.

## 10. Partial-differential protection

Partial-differential protection, sometimes called summation-overcurrent relaying, is a modification of a full differential scheme in which one or more of the load circuits are not included in the differential system sum (see Figure 24). This method is often used as backup protection for other overcurrent protection. There are several considerations to be thought through when implementing this protection. Using Figure 24 as reference, if the tie is closed and the left source circuit breaker is open, the right source could be supplying the full load on both the right and left buses. If both buses are fully loaded to 100% of their capacity, the right bus will be carrying 200% current even though its connected load is half of that. The partial differential sum will only measure 100% current because the tie is subtracting from the source. Because of this, it is important that the source circuit breakers have primary protection adequately sized to the capability of the buses and devices.

Another advantage occurs when partial differential schemes are applied on buses being fed from multiple parallel sources, which can otherwise be difficult to coordinate. Consider that the feeder overcurrent device in such a system will see all the current flowing to line-side faults, regardless of how the sources contribute to this current. The degree to which the sources may share can be difficult to predict and makes traditional representation on time current curves difficult. The relay in the partial differential scheme sees the same fault current as the feeder device or the faulted bus, regardless of how sources are sharing that current, making classic time current curve evaluation straightforward. The relay can disconnect all sources simultaneously selectively. Furthermore, the partial differential relay can be interlocked with blocking signals from the load-side overcurrent or ground fault relays allowing for faster protection of the bus without negatively impacting selectivity.

When a normally closed tie circuit breaker separates loads as shown in Figure 24, this scheme can provide selectivity between the two sources for bus faults and load-side faults. In a conventional scheme with relays on each incoming line, a fault on either bus results in a loss of both incoming lines because their settings are identical. With the partial differential scheme, a fault on one bus causes a summation of currents in one set of relays and a subtraction of currents in the other set of relays (not shown). This difference in currents allows the incoming line relays to be selective and only the faulted bus is de-energized.

Partial differential relays should provide sufficient delay to be selective with relays on the load circuits. Consequently, the sensitivity and speed of partial differential protection is not as good as in full differential protection. A partial differential scheme may be enhanced by use of blocking signals (ZSI) from load-side load relays to force the partial differential protection to be restrained if the fault is detected by load protection

relays, or trips fast enough. This requires that the blocking signal arrive at the device providing the partial differential protection before the partial differential protection commits to asserting a trip.

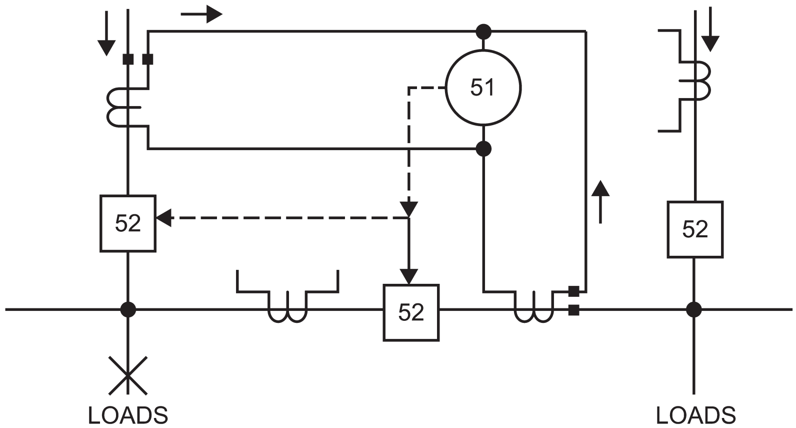



**Figure 24—Partial differential relaying (three-breaker scheme)**

## 11. Backup protection

To cover the situation when the primary protective system fails to operate as planned, some form of backup relaying and protection should be provided in the power system.

Bus backup protection is inherently provided by the primary relaying or trip units at the remote ends of the supply lines. This setup is known as remote-backup protection. It might not be adequate because of system instability and effects on other portions of the power system, and local-backup relaying might be necessary. The performance of various remote- and local-backup relaying schemes should be analyzed. IEEE Std C37.95-2014 [B19] gives further information on utility-service supply-line requirements and the backup protection of utility relaying.

Circuit-breaker failures can cause catastrophic results, such as complete system shutdown. In MV and HV applications, local circuit-breaker failure or stuck-circuit-breaker relay schemes are available to quickly trip supply-side circuit breakers that are able to isolate the failed protective device if the circuit breaker on the faulted circuit fails to operate within a specified time. These schemes were normally applied only on buses where the extra expense could be economically justified when discrete relays were the norm. Now, multifunction relays provide these functions without additional cost. In LV systems, backup protection is provided by upper tier devices employing nested delays or zone-selective-interlocking. It should be noted that the backup to a failed LV main, fed from a transformer, is provided by the first MV protective device ahead of the transformer. Unless protection has been implemented to specifically provide fast backup protection, the protection provided by an MV protector on the line side of a transformer, for a LV fault on the secondary side of the transformer, might be several orders of magnitude slower than the expected, failed, LV protection. This situation can lead to significant equipment damage and extremely hazardous levels of arc-flash energy. See the following clause in this recommended practice for some further discussion on this subject as well as Mello et al. [B24].

Some low-impedance differential relays incorporate multiple protective functions that can back up the protection provided by the differential-relay algorithm, as well as provide additional protection for feeder circuits.

# 12. Protecting the secondary terminals and connected bus on a step-down substation transformer

## 12.1 General discussion

Protection of the terminals and conductors on the secondary of a substation transformer can present unique challenges:

— The protective device, circuit breaker, switch, and fuses are located on the transformer primary circuit at a higher voltage than the secondary conductors that require sensitive protection;

— The distance might be significant between the MV protective device and the location where sensing for protection of the lower-voltage bus is located;

— The lower-voltage equipment might not easily accommodate instrument transformers of sufficient accuracy and burden capability to provide proper sensitivity and performance;

— The transformer winding configuration might further desensitize any primary-side sensing of secondary fault current;

— Transformer inrush current requirements require accommodation by any primary sensing and protection implemented.

It is common to protect secondary substation transformers with dedicated primary fused switches. However, the fuses often do not provide adequate protection of the secondary bus and can allow very large levels of incident arc-flash energy and equipment damage in the case of an equipment arcing fault. The fuses can provide adequate protection for large-magnitude faults on the primary connections of the transformer. The transformer ratio and relatively small magnitude of an arcing secondary fault can cause the fault to be difficult to detect with primary-side current sensing. The following subclauses describe some alternatives for protecting this section of the power-distribution system.

Ground-fault protection on the bus between the transformer secondary terminals and the first LV devices may be important. The NEC only requires ground-fault protection on service entrance disconnects rated at 1200 A or greater. However, the line side of the service entrance disconnects may also be subject to ground faults and should be protected for low magnitude arcing ground faults if possible. See Paul et al. [B28] for further discussion on ground faults between the transformer terminals and the first secondary protective device.

## 12.2 Low-voltage (LV) bus protection using primary-side protective devices

System designers might not employ secondary main circuit breakers in substations when the quantity of feeder circuit breakers is allowed by applicable codes. This arrangement can minimize cost, reduce footprint, and circumvent code required ground-fault protection. In such cases, the LV main-bus protection must come from the MV protective device on the primary side of the transformer. Usually, MV fuses used for transformer protection do not usually have characteristics suitable for secondary bus protection from arcing currents because these arcing currents are typically much smaller than the maximum secondary bolted fault current. If a system without a secondary main is contemplated, a circuit breaker as a primary device should be considered. Protection provided by the primary device should, as much as possible, sense and react to faults on the secondary side of the transformer with the same speed and sensitivity that a properly selected and set secondary main would provide. Such protection may be difficult to achieve with simple 50/51 protection on the primary side of the transformer or a fuse due to the required transformer inrush considerations. Overcurrent protection with secondary side sensing along with zone-selective-interlocking, or additional transformer differential protection, or bus differential protection encompassing all the LV main bus up to the transformer terminals will provide improved protection.

Omitting a secondary main from a double-ended substation (in this case, double-ended substation refers to a substation with two sources and a tie device on the bus that can be used to separate the sources) is not recommended. A fault on a transformer primary, which is directly connected to the main LV bus by the transformer, would be fed from both sources. The current from the opposite transformer is limited by the impedance of the two transformers. It might be small and difficult to detect by the overcurrent protection from the far transformer, and it might last for a long time causing significant damage and hazard.

## 12.3 Selection of transformer primary fuses for arc-flash protection on the transformer secondary bus

Selecting the optimum E-rated fuses (ANSI/IEEE C37.42) for transformer primary protection can reduce arc-flash incident energy levels at the secondary terminals to less than 40 calories/cm$^2$ in selected circumstances. Standard fuse application for transformer protection allows selecting fuses that meet codes and applicable standards, but when selected only per NEC requirements and acceptable selectivity, these might provide less protection to the transformer or secondary circuits than is desired. A fuse selected in this manner might be larger than necessary and provide less than optimal secondary arc-flash protection and transformer protection.

A fuse is only current-limiting when the fault current is sufficiently large to drive fuse performance into the fuse current-limiting range, above the threshold current, or current limiting threshold. If the fuse is selected with a larger current rating than needed, the threshold current is larger than might be prudent. The goal is to select a fuse size and type with a threshold current that is less than the least-expected secondary arcing current when reflected to the primary voltage. However, even if the secondary arcing fault current is less than the MV fuse current-limiting threshold, applying a fuse with an inverse time characteristic will shorten the duration of the arc current, resulting in less incident energy and less equipment damage at the secondary bus between the transformer and the first LV primary device.

The selection process of a primary fuse should include the following:

- Systems considerations such as maximum load current expected, steady-state and transient current, available source fault current, expected secondary arcing current;
- Transformer characteristics such as impedance, magnetizing current, applicable damage curves, output power, kVA; short-circuit voltage; service voltage; operation with or without overload;
- Local code requirements;
- Fuse characteristics for the multiple fuses considered such as:
  - Rated currrent, the current that the fuse can withstand without abnormal heating;
  - Minimum interrupting current, the minimum current that can melt the fuse. Generally, fuses should not be applied where the sustained load could range above fuse rating and below minimum melting current.

By selecting a smaller fuse ampere rating and a more extreme inverse-time characteristic, the incident energies may be substantially lessened at the secondary LV equipment. If the selection process is followed properly, the system should not have nuisance fuse openings and still be selectively coordinated. It is important to follow fuse manufacturers' guidelines and understand the expected transformer needs when tighter protection is implemented to not incur nuisance operation of the fuses upon energization of the transformer.

## 12.4 Zone-selective interlocking across a substation transformer

LV circuit-breaker trip unit systems often provide ZSI capability that allows trip units to be selective while providing minimally delayed protection. In modern circuit-breaker trip unit systems, zone-selective interlocking is available for ground-fault protection, short-time protection, and even instantaneous protection.

In component relays typically used in MV systems, a similar capability might go by various names such as blocking or instantaneous blocking systems. In both the LV and MV implementations, the basic theory is the same. In a distribution system composed of multiple tiers of devices, the load-side lower tiers send a signal to line-side upper tiers when sensing a fault above a preset threshold. The upper tier devices receive the signal and using internal logic, alter their tripping characteristics, typically slowing their response to allow the load-side device to clear the fault. The zone interlocking can be described as forcing the line-side device to shift to a backup protection role in the interest of maximizing selectivity.

The ability to extend the interlocking capability between the last primary protective device and the first secondary device is advantageous because it provides protection of the transformer secondary terminals and connected conductors without the need to compromise protection or selectivity. Also, there is no need to include long secondary conductors within a transformer differential scheme. Figure 26 shows multiple ways to design a scheme that uses LV-to-MV interlocking to protect the transformer primary and transformer secondary without sacrificing system reliability.

Protection of the transformer primary and secondary might be implemented using two separate relays or two protective elements within one relay. Sensing for secondary faults might be done using CTs located on the transformer primary or secondary. Secondary sensing might be easier to set sensitively because the transformer inrush current does not need to be considered. When the transformer secondary is a solidly grounded wye, attention must be paid to ground faults that are lesser magnitude and are also reduced to 58% of the ground current when sensed at the primary side (because of the wye-delta winding).

In 25(a) the zone-interlocking signal is routed from the LV equipment feeders to the LV main, and from the LV main to the MV relay. To improve the sensitivity of the MV relay protection, the restraint signal could be taken directly from the LV feeders allowing the LV main and MV transformer feeder to operate for equivalent faults—it makes no difference to the reliability of the substation.

In 25(b) the secondary LV circuit breaker is not included. In this configuration, the MV primary device is operated as an LV main. This configuration is not recommended for substations with multiple sources that could result in transformers energized from the LV side.

In 25(c) one or more relays can be used to implement transformer-differential and overcurrent protection of load-side conductors simultaneously. This configuration might be easier to implement than a transformer differential scheme that includes the secondary conductors within the zone of protection. Various considerations might affect the selection of a scheme that includes the secondary bus in the differential zone of protection or relies on protection with a 50/51 device. The considerations are the following:

- Length of secondary conductors and distance between sensors in the secondary equipment and the MV relay;
- Required size of secondary CTs required for differential protection might be difficult to locate within the LV equipment;
- Desensitizing differential sensing required to account for transformer magnetizing current;
- Access to a fast blocking signal from an LV trip unit or protective relay system;
- Ability and time to process a blocking signal for 50/51 protective elements.

Discussed in 8.4 is the subject of modeling the settings and timing of an LV-side sensing scheme interlocked with MV-side protection. The figures below depict the implementation of the three different transformer secondary bus protection schemes discussed in this subclause.

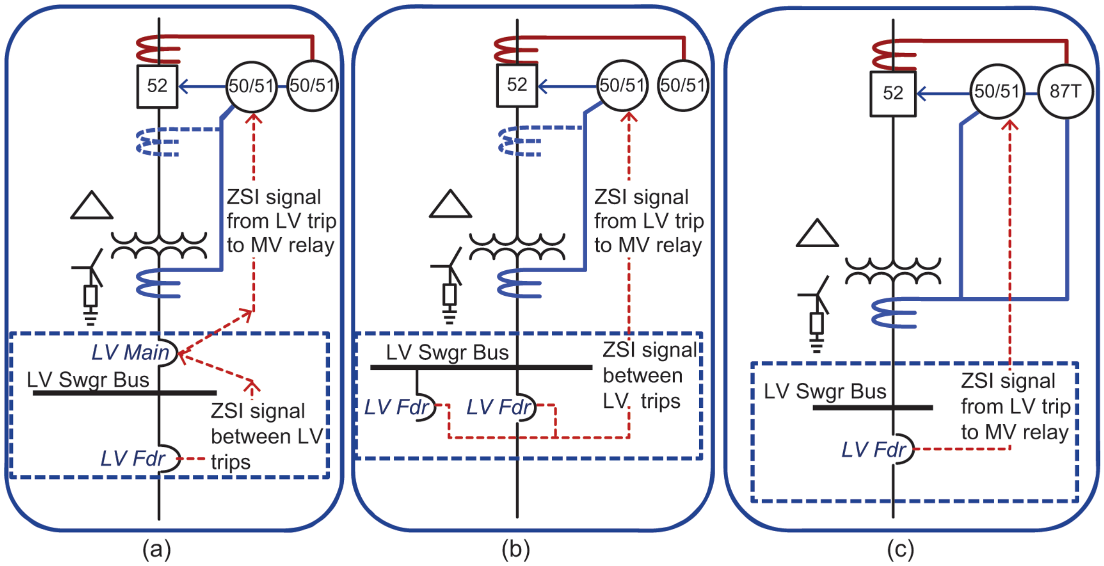



**Figure 25—Interlocking secondary-protective devices to primary-protective devices**

# 13. Low-voltage bus conductors, switchgear, switchboard, and motor control-center protection

LV switchgear listed to UL 1558 and built to IEEE C37.20.1 standards have a short-circuit rating and a short-time withstand rating. Low-voltage equipment such as switchboards listed to UL 891, motor-control centers listed to UL 845, and panelboards listed to ANSI/UL67 have short-circuit ratings but do not have a requirement, per standard, for a short-time withstand rating. Manufacturers might offer a short-time withstand rating, but this will apply, usually, only to the main horizontal bus. Within IEC standards, a single standard is used to define the multiple types of LV power distribution equipment, and short-time withstand ratings are optional for all equipment types.

LV power circuit-breaker switchgear built to the IEEE C37.20.1 standard can only employ LV power circuit breakers (LVPCB). These circuit breakers can be supplied both with and without series fuses. Switchboards and motor-control centers can be designed to include LVPCBs, molded case circuit breakers (MCCB), or fusible load-break switches. Each of these protective devices has different characteristics that should be considered from the bus protection perspective. Equipment manufacturers generally implement protective devices that are compatible with the capabilities of the equipment. Implementing external protective relays to provide protection by operating LVPCB without using the circuit breaker's integral protection as backup can cause circuit breakers to operate slower than the equipment can withstand. If relays are required for complex protection or control applications, the circuit breaker trip should be included to ensure that protection is no slower than the equipment or circuit breaker can withstand. For protection where fast instantaneous fault clearing is required, it is likely that the integral trip will be faster than an external protective relay.

Equipment buses protected by current-limiting fuses will, under most circumstances, be well coordinated and well protected from large-magnitude bolted-fault currents occurring within the equipment or flowing through the equipment. However, as fuse continuous rating increases, they may provide slow protection for lesser-magnitude arcing currents, and the protection might not be enough for adequate arc-flash incident energy mitigation. If arc-flash incident-energy mitigation is expected to be provided by LV fuses, it is important to verify that expected arcing currents are large enough to cause the fuses to operate at the speed required to provide the desired level of arc-flash incident energy mitigation desired. Equipment buses protected by

LVPCB[13], or large insulated case circuit breakers[14] might use nested delays to achieve selectivity. Multiple levels of circuit breakers coordinated with nested delays might result in main breakers with short-time clearing times of several hundred milliseconds. Nested delays might also result in main or even feeder circuit breakers with decreased sensitivity and increased clearing times at the levels required to protect against arcing faults, resulting in slower clearing times and significant incident energy and equipment damage.

Instantaneous trips in circuit breakers provide faster protection than short-time delays; however, these can negatively impact selectivity. Methods to coordinate circuit breakers with instantaneous trips have been developed by various manufacturers. Manufacturers should be consulted to properly optimize the selectivity that might be possible using any one manufacturer's device(s). The protection afforded by short delays can also be improved with the use of zone-selective interlocking schemes between circuit breakers and ground-fault relays in fusible switches. Bus-differential protection is another protection scheme that might be used to protect LV buses. Using a combination of these capabilities can provide protection that is sensitive to a wide range of bus-fault magnitudes while maintaining selectivity for large fault magnitudes. For further reading on this subject, see NEMA publications on selectivity [B25] and [B26] as well as Valdes et al. [B41].

## 14. Special considerations for arc-flash hazard reduction

IEEE Std 1584 defines arc-flash hazard as "a dangerous condition associated with the release of energy caused by an electric arc." The degree of hazard is affected by the amount of time required by the overcurrent protective device to clear the arcing current. Protective device settings required to achieve reliable power distribution system operation might result in overcurrent devices operating at clearing times slower than these might otherwise be able to provide at the arcing current predicted. One potential technique to reduce operating times temporarily, when improved protection might be preferred over optimized selectivity, is to use an alternate settings group. Many digital microprocessor-based relays can provide a second set of settings (via a setting-group change) that might be easily or remotely enabled for temporary improved protection. LV circuit breakers can also provide temporary settings that might lower the pickup or enable the instantaneous trip of a circuit breaker as well as override short delays or reduce instantaneous clearing times. Specific implementations of this function vary by manufacturer.

Remote operation of circuit breakers or switches and remote racking capability might also be employed to reduce the exposure of operating personnel to arc-flash hazard and should be considered whenever possible. Most devices available in the industry have capability for remote operation. Use of digital microprocessor-based relays in MV systems and digital trips in LV systems, both of which can use powerful communication, allow implementation of remote control, metering, and diagnostic systems that can significantly reduce the need for operating personnel to enter the flash protection boundary. Because of the increased safety these methods provide, these capabilities should be considered whenever possible and practicable.

IEC MV equipment standards (IEC 62271-200 2011) specifically address this same concern by describing these "supplementary" measures to provide additional personnel protection:

a) Fast fault clearing via light, pressure, heat, or differential current sensing protection;
b) Controllable type fuses made up of a current limiting fuse in parallel with a current path that can be opened quickly to commutate the current to the parallel current limiting path;
c) Extremely fast elimination of the arc by diverting the current to an arc quenching device that shunts fault current and collapses voltage to eliminate the arcing fault;
d) Remote operation of equipment;

[13]Low-voltage power circuit breakers (LVPCB) are a specific type of LV circuit breaker which complies with IEEE Std C37.13. These circuit breakers may also be listed devices under UL1066.
[14]Insulated case circuit breakers are UL 489 listed circuit breakers that share some characteristics of LVPCB. See IEEE Std 3004.5 for further information.

e) Pressure relief mechanism;

f) Closed door draw-out.

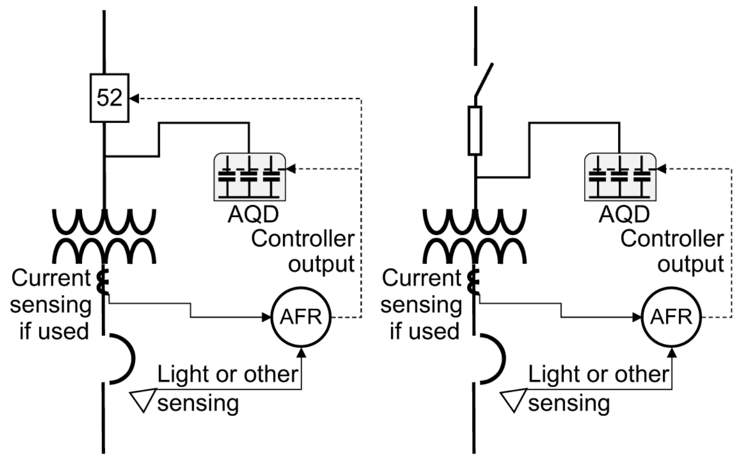
# 15. Arc quenching devices (AQDs)

Another way to provide bus protection is to use a shunt energy-diversion device called an arc quenching device (AQD) within IEC practices and sometimes referred to as a crowbar, shorting switch, or fast earthing switch. These devices are connected as a load on the main bus or ahead of the main bus. When these are operated, they close and provide a fault current path that collapses available voltage and quickly extinguishes any arcing fault on the system. These devices have the advantage of providing very fast operation, they can extinguish an arcing fault in less than a half cycle including sensing and control timing, depending upon the sensing and control method used. The most common type is the zero-impedance or solid-conductor crowbar. The solid conductor devices cause bolted-fault current to flow and hence a near complete collapse of system voltage. The solid-conductor type devices have been used in Europe with success for several years. The solid-conductor type crowbar is, generally, a one-time-use device and might be applied as temporary protection to be used only during hazardous maintenance activity. It is possible that the high current caused by devices that fully short circuit the connected bus can stress system components, and that risk should be considered. Therefore, some shunt-energy devices that rely on the limited-impedance of a controlled have been introduced for LV applications. Due to the arc impedance, these devices do not draw full bolted-fault current, thus stressing system components less and lessening the risk of system damage during an operation. However, these limited-impedance devices may have a more restricted range of application. Arc-fault mitigation is similar for both types of devices. Because arc-quenching devices are connected in parallel to the bus system, tap cables can connect to existing systems to reduce arc-flash hazard as part of an arc-flash hazard mitigation project.

When considering use of this kind of device, the manufacturer should be consulted and applicability to the system carefully considered. These devices have excellent arc-flash, incident-energy mitigation, and in some applications, such as a retrofit in an existing installation, these might provide one of very few practical alternatives to achieve small levels of incident energy. However, there are risks and limitations that must be considered in consultation with the respective manufacturers.

Arc quenching devices may be controlled with arc-flash relays (see Clause 16), simple overcurrent detection, differential relays, and other sensing logic. This logic might be implemented in a continuous protection mode or as part of a temporary protection scheme used during hazardous maintenance or operation activity. The latter is sometimes recommended because of the possible impact or cost of nuisance operation. For further reading concerning shunt energy absorbing devices, see Kay et al. [B23] and Roscoe et al. [B31].

Shorting switches have been used to create a low impedance path for fault current in some MV and HV circuits to ensure that overcurrent relays protecting the circuit sensed the current as fast as possible. These same devices, and others like them, are now also used for arc-flash protection as described in this subclause.




One way to implement an AQD for a substation with LV secondary. The AQD may be controlled any of several ways, often using an arc flash relay. When CB is used to stop current the flowing into the AQD the controller for the AQD also controls the disconnecting circuit breaker.

Another way to implement an AQD for a substation with LV secondary. When the AQD operates the current through the AQD collapses the secondary voltage and should, simultaneously, melt the fuses within their current limiting range thereby limiting the peak current.

**Figure 26—Two of several ways to implement a MV AQD for LV protection of a substation secondary bus**

## 16. Arc-flash relays

Arc-flash relays are protective devices specifically designed to sense an electrical explosion as evidence by the sensor or sensing method they implement. The most common relay is based on sensing light. Others may use sound or pressure. Most arc-flash relays can also use a current signal to corroborate the primary light or pressure signal is not caused by a source other than an arcing current fault within the protected volume. This type of relay has been in use in IEC practices for MV equipment for over a decade and can provide very fast protection from arcing faults. Relays may assert a fault via its output contact in 1 or 2 ms. Most will operate in less than half a cycle. However, if used with current confirmation, the response may be slower. In some cases, other relays such as standard feeder protection relays (50/51) or other protection relays of various types may allow implementation of additional light sensors to complement the overcurrent protection they provide.

When implementing a light-based arc-flash relay, it is important to understand that the relay is a volume protector, not a circuit protector. It can sense that there is light above threshold within the volume the sensors are applied. But it cannot differentiate one circuit from another if there are multiple circuits within the volume, nor can they detect a remote arcing fault within a circuit if the fault is within a remote volume.

Light-based relays can also nuisance operate if they perceive light from another source as being light caused by an accidental arcing event. Current-sensing based confirmation is implemented to protect against this possibility; however, light could be caused by an electromagnetic air circuit breaker interrupting a remote fault within the protected volume. Current sensing may not differentiate the light from an interrupting circuit breaker or from a non-electrical source, from the light generated by an accidental electrical arc. Arc-flash relays implemented near fuses, sealed vacuum circuit breakers, or gas insulated equipment would not be subjected to light from the operation of those devices. If using an arc-flash relay around low voltage circuit breakers, it may be advisable to use the relay only during maintenance or implement another method to minimize the possibility of a nuisance operation due to an interrupting LV circuit breaker. See Roscoe et al. [B32] for additional reading on this subject. In articles 240.67 and 240.87 of the NEC (2017), there is a function referred to as an energy

reducing switch (ERMS) that is expected to be used only during maintenance similar to how it is suggested for an arc-flash relay in applications where a nuisance trip presents an unacceptable risk.

As with all protective relays, it is important to not confuse the relay operating time with fault clearing time. Fault clearing time must include the controlled circuit breaker operating time as well as any intermediary relays or other sources of delay.

When considering use of an arc-flash relay, the manufacturer should be consulted for exact application guidelines as they may vary from manufacturer to manufacturer.

## 17. Triggered current limiters (TCLs)

A triggered current limiter, sometimes also called a commutating current limiter, is a device that consists of a main current conducting path with a parallel current limiting fuse. During normal operation current mostly flows through the main current path. Typically, some type of very fast integral relay and sensing is provided that, based upon a user set trigger threshold, will open the main conducting path commutating the current to the current limiting fuse, which then interrupts the current very quickly. Often these devices will require that components be replaced after a fault operation. The devices are only designed for fault operation and are not used for normal switching applications. Devices are available for application for the LV and MV range.

In addition to opening very fast, these devices can be used as fault current limiters to protect otherwise underrated equipment; however, they should not be used for that purpose in new system designs if full rated equipment is available. In some applications, such as retrofitting existing installations, these devices may provide one of few practical alternatives to achieve lower levels of incident energy or protect equipment that is underrated for the available prospective short-circuit current. However, there are limitations that must be considered in consultation with the respective manufacturers.

## 18. Voltage-surge protection

Protection against voltage surges should be considered for all switchgear assemblies that have exposed circuits. Exposed circuits are those outside buildings or those that do not have adequate surge protection connected to limit voltages to less than the withstand level of the switchgear. A circuit connected to open-line wires through a power transformer is not considered exposed if adequate protection is provided on the line side of the transformer. Circuits confined entirely to the interior of a building, such as an industrial plant, are not considered exposed to lightning surges and might not require lightning surge protection. Contact the utility serving the premises to determine the possibility of switching surges resulting from capacitor switching.

Coordinate the system voltage rating with the surge arrester voltage rating for surge protection selectivity when protection is installed on transformer primary. Consult with the manufacturers for application.

For further discussion of voltage surge protection, see Chapter 6 in IEEE Std 141 (*IEEE Red Book*™), 7.8 of IEEE Std C37.20.3-2001, IEEE Std C62.22, and IEEE Std C62.92.1.

## 19. Conclusions

Because of its importance in the electric power system, the bus and switchgear should be designed, located, and maintained to prevent faults as well as to protect quickly when faults happen. System reliability and safety is promoted by good protection as well as by good systems design; designing for maintainability, future expansion when applicable, and by considering prevention through design practices that maximize safety for maintenance and operating personnel. IEEE standards in the 3007 series of operation, maintenance, and safety standards [B15], [B16], and [B17] offer guidance on these subjects.

The preferred protection practice for switchgear buses applied at 1 kV or greater is differential protection. But today, in an arc-flash conscious world, differential protection should be considered for LV buses as well. In LV systems, arcing currents can be substantially lower than bolted fault currents, hence the sensitivity of protection is as important as the operating time. Differential protection can get around the need to use ever increasing thresholds that eventually cause important bus protection to be insufficiently sensitive to provide desired protection. For additional reading, see Pavavicharn et al. [B29] and Rifaat [B30]. Arc-flash relays provide an alternative to bus differential protection or a way to compliment bus differential protection. Light-based sensing technology has been available for several years but is rapidly evolving with new products frequently being introduced into the market.

Improved zone-selective-interlocking capabilities available in protective relays and integral LV trip units provide additional ways to improve bus protection over traditional nested threshold and nested static time delay-based selectivity. Protection of buses, such as the one between a distribution transformer's terminals and the first secondary overcurrent protector, is important for arc-flash protection as well as for system reliability. Today, multiple manufacturers offer systems, devices, and protection schemes specifically targeting buses in LV substations including the bus between the secondary substation transformer LV terminals and the first LV overcurrent device in the system. Such protection may not have been considered important enough to warrant the cost or complexity just a few years ago, but today the importance has grown and the complexity and cost are lower. For further reading, see Valdes et al. [B41], and Hodgson and Shipp [B8].

Modern digital relays with embedded computers able to handle complex computational tasks and complex logic are commonly and more cost effectively available from multiple manufacturers. Advances in electronics and sensing facilitate improvements in the products available. Schemes that in the past required many dedicated CTs connected to dedicated single function relays can now be implemented with fewer CTs connected to multifunction protective relays. Additional communications, metering, and diagnostic capabilities provided by the same relays add to the value provided by the investment and expand the range of benefits the devices can provide. The industry has also introduced new switching devices that allow relay-controlled protection in applications that formerly were relegated to simpler and lower cost but more limited protection. How a bus is configured is also important to its long-term protection. How it is connected to its sources, interconnection circuit breakers or ties, bus transfer schemes, and other factors will affect safety, ability to maintain system reliability, and the capability for future growth. How reliable and well protected a bus is will depend on these factors as well as on the relaying used. Location of the equipment in a good environment and maintenance on a planned basis helps prevent faults, may prevent nuisance operations by protective devices, and ensures the devices operate as expected when called upon to do so. If a fault does occur, high-speed, sensitive relaying limits the damage so that repairs can be made quickly, and service is restored in a short time. Fast clearing of arcing faults also can save lives by minimizing the electrical explosion and consequent arc-flash hazard.

Modern technology and continuous innovation provide an ever-increasing array of alternatives; it is up to the system design and protection engineer to fully take advantage of them.

# Annex A

(informative)

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